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SOUTHERN COMPANY
Energy to Serve Your World℠

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NL-04-0564

Docket Nos.: 50-321 50-348 50-424
50-366 50-364 50-425

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555-0001

Edwin I. Hatch Nuclear Plant
Joseph M. Farley Nuclear Plant
Vogtle Electric Generating Plant
Application for Technical Specification Amendment to
Eliminate Requirements for Hydrogen Recombiners and Hydrogen/Oxygen Monitors
Using the Consolidated Line Item Improvement Process

Ladies and Gentlemen:

Pursuant to 10 CFR 50.90, Southern Nuclear Operating Company (SNC) hereby requests amendments to the Technical Specifications (TS) for Units 1 and 2 of the Edwin I. Hatch Nuclear Plant (HNP), the Joseph M. Farley Nuclear Plant (FNP), and the Vogtle Electric Generating Plant (VEGP).

The proposed amendment will delete the TS requirements related to hydrogen recombiners, hydrogen monitors, and oxygen monitors. The proposed TS changes support implementation of the revision to 10 CFR 50.44, "Standards for Combustible Gas Control System in Light-Water-Cooled Power Reactors," that became effective on October 16, 2003. The changes are consistent with Revision 1 of NRC-approved Industry/Technical Specification Task Force (TSTF) Standard Technical Specification Change Traveler, TSTF-447, "Elimination of Hydrogen Recombiners and Change to Hydrogen and Oxygen Monitors." The availability of this TS improvement was announced in the Federal Register on September 25, 2003 as part of the consolidated line item improvement process (CLIIP).

Enclosure 1 provides the basis for the proposed changes for HNP Units 1 and 2, FNP Units 1 and 2, and VEGP Units 1 and 2. This includes a description of the proposed changes, the confirmation of applicability, plant-specific verifications, the no significant hazards determination, and the environmental evaluation. Enclosure 2 provides the existing TS and TS Bases pages marked-up to show the proposed changes and the clean typed copies of the affected pages for HNP Units 1 and 2. Enclosures 3 and 4 similarly provide the marked-up and clean typed TS and TS Bases pages for FNP Units 1 and 2 and VEGP Units 1 and 2, respectively.

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The NRC commitments contained in this letter are provided in section 6.1 of Enclosure 1 for HNP, FNP and VEGP.

SNC requests approval of the proposed License Amendment by March 1, 2005 for HNP in order to support the spring 2005 Unit 2 outage and June 1, 2005 for FNP and VEGP. The proposed changes will be implemented within 60 days of issuance of the amendment.

Mr. L. M. Stinson states he is a Vice President of Southern Nuclear Operating Company, is authorized to execute this oath on behalf of Southern Nuclear Operating Company and to the best of his knowledge and belief, the facts set forth in this letter are true.

If you have any questions regarding this submittal, please advise.

Respectfully submitted,

SOUTHERN NUCLEAR OPERATING COMPANY

L. M. Stinson

Sworn to and subscribed before me this 21 *day of* May, *2004.*

Notary Public

My commission expires: 6-7-05

LMS/TDH/daj

Enclosure 1: Basis for Proposed Change
Enclosure 2: HNP Marked-up and Clean-typed TS and TS Bases Pages
Enclosure 3: FNP Marked-up and Clean-typed TS and TS Bases Pages
Enclosure 4: VEGP Marked-up and Clean-typed TS and TS Bases Pages

cc: Southern Nuclear Operating Company
Mr. J. B. Beasley, Jr., Executive Vice President
Mr. L. M. Stinson, Vice President, Plant Farley
Mr. H. L. Sumner, Jr., Vice President, Plant Hatch
Mr. J. T. Gasser, Vice President, Plant Vogtle
Mr. D. E. Grissette, General Manager – Plant Farley
Mr. G. R. Frederick, General Manager – Plant Hatch
Mr. W. F. Kitchens, General Manager – Plant Vogtle
RType: CFA04.054; CHA02.004; CVC7000; LC# 14018

U. S. Nuclear Regulatory Commission
Dr. W. D. Travers, Regional Administrator
Mr. S. E. Peters, NRR Project Manager – Farley
Mr. C. Gratton, NRR Project Manager – Hatch
Mr. C. Gratton, NRR Project Manager – Vogtle
Mr. C. A. Patterson, Senior Resident Inspector – Farley
Mr. D. S. Simpkins, Senior Resident Inspector – Hatch
Mr. J. Zeiler, Senior Resident Inspector – Vogtle

State of Alabama
Dr. D. E. Williamson, State Health Officer - Department of Public Health

State of Georgia
Mr. L. C. Barrett, Commissioner - Department of Natural Resources

Enclosure 1

Edwin I. Hatch Nuclear Plant
Joseph M. Farley Nuclear Plant
Vogtle Electric Generating Plant
Application for Technical Specification Amendment to
Eliminate Requirements for Hydrogen Recombiners and Hydrogen and Oxygen Monitors
Using the Consolidated Line Item Improvement Process

Basis for Proposed Change

Enclosure 1
Edwin I. Hatch Nuclear Plant
Joseph M. Farley Nuclear Plant
Vogtle Electric Generating Plant
Application for Technical Specification Amendment to
Eliminate Requirements for Hydrogen Recombiners and Hydrogen and Oxygen Monitors
Using the Consolidated Line Item Improvement Process

1.0 INTRODUCTION

The proposed License amendment deletes Technical Specification (TS) requirements for the "Hydrogen Recombiners," and deletes references to the hydrogen and oxygen monitors in "Post Accident Monitoring (PAM) Instrumentation" sections of the TS. The proposed TS changes support implementation of the revisions to 10 CFR 50.44, "Standards for Combustible Gas Control System in Light-Water-Cooled Power Reactors," that became effective on October 16, 2003. The deletion of the requirements for the hydrogen recombiner and references to hydrogen and oxygen monitors resulted in numbering and formatting changes to other TS, which were otherwise unaffected by this proposed amendment.

The changes are consistent with Revision 1 of NRC-approved Industry/Technical Specification Task Force (TSTF) Standard Technical Specification Change Traveler, TSTF-447, "Elimination of Hydrogen Recombiners and Change to Hydrogen and Oxygen Monitors." The availability of this TS improvement was announced in the Federal Register on September 25, 2003 as part of the consolidated line item improvement process (CLIIP).

2.0 DESCRIPTION OF PROPOSED AMENDMENT

Consistent with the NRC-approved Revision 1 of TSTF-447, the proposed TS changes include:

Edwin I. Hatch Nuclear Plant (HNP)

TS TOC, page iii (Unit 2 only)	Item 3.6.3.1	Deleted
TS Table 3.3.3.1-1	Item 7, Drywell Hydrogen Concentration	Deleted
TS Table 3.3.3.1-1	Item 8, Drywell Oxygen Concentration	Deleted
TS 3.6.3.1 (Unit 2 only)	Primary Containment Hydrogen Recombiners	Deleted

Joseph M. Farley Nuclear Plant (FNP)

TS TOC, page ii	Item 3.6.7	Deleted
TS 3.3.3	Condition C, Note	Deleted
TS 3.3.3	Condition D	Deleted
TS Table 3.3.3-1	Item 18, Hydrogen Monitors	Deleted
TS 3.6.7	Hydrogen Recombiners	Deleted

Vogtle Electric Generating Plant (VEGP)

TS TOC, page iii	Item 3.6.7	Deleted
TS 3.3.3	Condition I	Deleted
TS Table 3.3.3-1	Item 19, Containment Hydrogen Monitors	Deleted
TS 3.6.7	Hydrogen Recombiners	Deleted

HNP Unit 1 was originally licensed with a combustible gas strategy of purging and venting; therefore, it does not have Post-LOCA (Loss of Coolant Accident) recombiners. Consequently, the elimination of HNP TS 3.6.3.1 only applies to HNP Unit 2. Other TS changes included in this application are limited to renumbering and formatting changes that resulted directly from the deletion of the above requirements related to hydrogen recombiners and hydrogen and oxygen monitors. As described in NRC-approved Revision 1 of TSTF-447, the changes to TS requirements and associated renumbering of other TS results in changes to various TS Bases sections.

3.0 BACKGROUND

The background for this application is adequately addressed by the NRC Notice of Availability published on September 25, 2003 (68 FR 55416), TSTF-447, the documentation associated with the 10 CFR 50.44 rulemaking, and other related documents.

4.0 REGULATORY REQUIREMENTS AND GUIDANCE

The applicable regulatory requirements and guidance associated with this application are adequately addressed by the NRC Notice of Availability published on September 25, 2003 (68 FR 55416), TSTF-447, the documentation associated with the 10 CFR 50.44 rulemaking, and other related documents.

5.0 TECHNICAL ANALYSIS

SNC has reviewed the safety evaluation (SE) published on September 25, 2003 (68 FR 55416) as part of the CLIIP Notice of Availability. The analysis included a review of the NRC staff's SE, as well as the supporting information provided to support TSTF-447. SNC has concluded that the justifications presented in the NRC approved TSTF and the SE prepared by the NRC staff are applicable to Units 1 and 2 of FNP, HNP, and VEGP and justify this amendment for the incorporation of the changes to the applicable TS.

6.0 REGULATORY ANALYSIS

A description of this proposed change and its relationship to applicable regulatory requirements and guidance was provided in the NRC Notice of Availability published on September 25, 2003 (68 FR 55416), TSTF-447, the documentation associated with the 10 CFR 50.44 rulemaking, and other related documents.

6.1 Verification and Commitments

As discussed in the model SE published in the Federal Register on September 25, 2003 (68 FR 55416) for this TS improvement, SNC is making the following verification and regulatory commitments:

1. SNC has verified that a hydrogen monitoring system capable of diagnosing beyond design-basis accidents is installed at FNP, HNP, and VEGP and is making a regulatory commitment to maintain that capability at the appropriate Regulatory Guide 1.97 category. The hydrogen monitors will be included in the post accident monitoring instrument program described in the FNP FSAR section 6.2.5, HNP Unit 2 FSAR section 7.5.3, and VEGP FSAR section 7.5.2. The FSAR will be revised at the next scheduled update following implementation of the TS amendment.

2. SNC has verified that FNP and VEGP do not have inerted containments. Therefore, an oxygen monitoring system is not applicable.

3. SNC has verified that an oxygen monitoring system capable of verifying the status of the inerted HNP Units 1 and 2 containments is installed at HNP and is making a regulatory commitment to maintain that capability. HNP uses two separate O_2 analyzers for monitoring the primary containment environment. HNP uses a commercial grade analyzer for the purposes of monitoring the containment during normal operation, thus satisfying the requirements of TS Surveillance Requirement (SR) 3.6.3.2.1. HNP uses Regulatory Guide 1.97 category 1 instrumentation for post-accident monitoring purposes. SNC commits to maintaining a monitor for insuring the primary containment is inerted (<4% O_2 by volume) during normal operation. SNC also commits to maintaining a post-accident O_2 analyzer for the purpose of insuring that the post-LOCA containment environment remains inerted. The post-accident O_2 monitor will be maintained at the appropriate Regulatory Guide 1.97 category.

   The commitment to maintain the post-accident H_2 and O_2 monitors will be maintained for both HNP Units 1 and 2, in the Unit 2 FSAR, section 7.5.3. The FSAR will be revised at the next scheduled update following implementation of this TS amendment. The post accident O_2 monitors will be added to the Technical Requirements Manual simultaneously with the implementation of this TS amendment.

7.0 NO SIGNIFICANT HAZARDS CONSIDERATION

SNC has reviewed the proposed no significant hazards consideration determination published on September 25, 2003 (68 FR 55416) as part of the CLIIP. SNC has concluded that the proposed determination presented in the notice is applicable to Units 1 and 2 of FNP, HNP, and VEGP and the determination is hereby incorporated by reference to satisfy the requirements of 10 CFR 50.91(a).

8.0 ENVIRONMENTAL EVALUATION

SNC has reviewed the environmental evaluation included in the model SE published on September 25, 2003 (68 FR 55416) as part of the CLIIP. SNC has concluded that the staff's findings presented in that evaluation are applicable to Units 1 and 2 of FNP, HNP, and VEGP and the evaluation is hereby incorporated by reference for this application.

9.0 PRECEDENT

This application is being made in accordance with the CLIIP. SNC is not proposing variations or deviations from the TS changes described in TSTF-447 or the NRC staff's model SE published on September 25, 2003 (68 FR 55416).

10.0 REFERENCES

Federal Register Notice: Notice of Availability of Model Application Concerning Technical Specification Improvement To Eliminate Hydrogen Recombiner Requirement, and Relax the Hydrogen and Oxygen Monitor Requirements for Light Water Reactors Using the Consolidated Line Item Improvement Process, published September 25, 2003 (68 FR 55416).

Enclosure 2

Edwin I. Hatch Nuclear Plant
Joseph M. Farley Nuclear Plant
Vogtle Electric Generating Plant
Application for Technical Specification Amendment to
Eliminate Requirements for Hydrogen Recombiners and Hydrogen and Oxygen Monitors
Using the Consolidated Line Item Improvement Process

HNP Marked-up and Clean Typed TS and Bases Pages

(continued)

Table 3.3.3.1-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

	FUNCTION	REQUIRED CHANNELS	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1
1.	Reactor Steam Dome Pressure	2	E
2.	Reactor Vessel Water Level		
	a. -317 inches to -17 inches	2	E
	b. -150 inches to +60 inches	2	E
	c. 0 inches to +60 inches	2	E
	d. 0 inches to +400 inches	1	NA
3.	Suppression Pool Water Level		
	a. 0 inches to 300 inches	2	E
	b. 133 inches to 163 inches	2	E
4.	Drywell Pressure		
	a. -10 psig to +90 psig	2	E
	b. -5 psig to +5 psig	2	E
	c. 0 psig to +250 psig	2	E
5.	Drywell Area Radiation (High Range)	2	F
6.	Primary Containment Isolation Valve Position	2 per penetration flow path [a][b]	E
7.	~~Drywell H_2 Concentration~~ (Not Used)	~~2~~	~~E~~
8.	~~Drywell O_2 Concentration~~	~~2~~	~~E~~
9.	Suppression Pool Water Temperature	2[c]	E
10.	Drywell Temperature in Vicinity of Reactor Level Instrument Reference Leg	6	E
11.	Diesel Generator (DG) Parameters		
	a. Output Voltage	1 per DG	NA
	b. Output Current	1 per DG	NA
	c. Output Power	1 per DG	NA
	d. Battery Voltage	1 per DG	NA
12.	RHR Service Water Flow	2	E

(a) Not required for isolation valves whose associated penetration flow path is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

(b) Only one position indication channel is required for penetration flow paths with only one installed control room indication channel.

(c) Monitoring each of four quadrants.

Table 3.3.3.1-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

	FUNCTION	REQUIRED CHANNELS	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1
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	c. 0 inches to +60 inches	2	E
	d. 0 inches to +400 inches	1	NA
3.	Suppression Pool Water Level		
	a. 0 inches to 300 inches	2	E
	b. 133 inches to 163 inches	2	E
4.	Drywell Pressure		
	a. -10 psig to +90 psig	2	E
	b. -5 psig to +5 psig	2	E
	c. 0 psig to +250 psig	2	E
5.	Drywell Area Radiation (High Range)	2	F
6.	Primary Containment Isolation Valve Position	2 per penetration flow path[a][b]	E
7.	~~Drywell H_2 Concentration~~ (Not Used)	~~2~~	~~E~~
8.	~~Drywell O_2 Concentration~~	~~2~~	~~E~~
9.	Suppression Pool Water Temperature	2[c]	E
10.	Drywell Temperature in Vicinity of Reactor Level Instrument Reference Leg	6	E
11.	Diesel Generator (DG) Parameters		
	a. Output Voltage	1 per DG	NA
	b. Output Current	1 per DG	NA
	c. Output Power	1 per DG	NA
	d. Battery Voltage	1 per DG	NA
12.	RHR Service Water Flow	2	E

(a) Not required for isolation valves whose associated penetration flow path is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

(b) Only one position indication channel is required for penetration flow paths with only one installed control room indication channel.

(c) Monitoring each of four quadrants.

~~Primary Containment Hydrogen Recombiners~~
3.6.3.1

(Not Used)

(Not Used)

3.6 CONTAINMENT SYSTEMS

3.6.3.1 ~~Primary Containment Hydrogen Recombiners~~

LCO 3.6.3.1 Two primary containment hydrogen recombiners shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One primary containment hydrogen recombiner inoperable.	A.1 ----------NOTE---------- LCO 3.0.4 is not applicable. ---------- Restore primary containment hydrogen recombiner to OPERABLE status.	30 days
B. Two primary containment hydrogen recombiners inoperable.	B.1 Verify by administrative means that the hydrogen control function is maintained.	1 hour AND Once per 12 hours thereafter
	AND B.2 Restore one primary containment hydrogen recombiner to OPERABLE status.	7 days
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3.	12 hours

(Not Used)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1.1	Perform a system functional test for each primary containment hydrogen recombiner.	24 months
SR 3.6.3.1.2	Visually examine each primary containment hydrogen recombiner enclosure and verify there is no evidence of abnormal conditions.	24 months
SR 3.6.3.1.3	Perform a resistance to ground test for each heater phase.	24 months

(continued)

Table 3.3.3.1-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

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2.	Reactor Vessel Water Level		
	a. -317 inches to -17 inches	2	E
	b. -150 inches to +60 inches	2	E
	c. 0 inches to +60 inches	2	E
	d. 0 inches to +400 inches	1	NA
3.	Suppression Pool Water Level		
	a. 0 inches to 300 inches	2	E
	b. 133 inches to 163 inches	2	E
4.	Drywell Pressure		
	a. -10 psig to +90 psig	2	E
	b. -5 psig to +5 psig	2	E
	c. 0 psig to +250 psig	2	E
5.	Drywell Area Radiation (High Range)	2	F
6.	Primary Containment Isolation Valve Position	2 per penetration flow path [a][b]	E
7.	(Not used)		
8.	(Not used)		
9.	Suppression Pool Water Temperature	2[c]	E
10.	Drywell Temperature in Vicinity of Reactor Level Instrument Reference Leg	6	E
11.	Diesel Generator (DG) Parameters		
	a. Output Voltage	1 per DG	NA
	b. Output Current	1 per DG	NA
	c. Output Power	1 per DG	NA
	d. Battery Voltage	1 per DG	NA
12.	RHR Service Water Flow	2	E

(a) Not required for isolation valves whose associated penetration flow path is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

(b) Only one position indication channel is required for penetration flow paths with only one installed control room indication channel.

(c) Monitoring each of four quadrants.

Table 3.3.3.1-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

	FUNCTION	REQUIRED CHANNELS	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1
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	a. -317 inches to -17 inches	2	E
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	c. 0 inches to +60 inches	2	E
	d. 0 inches to +400 inches	1	NA
3.	Suppression Pool Water Level		
	a. 0 inches to 300 inches	2	E
	b. 133 inches to 163 inches	2	E
4.	Drywell Pressure		
	a. -10 psig to +90 psig	2	E
	b. -5 psig to +5 psig	2	E
	c. 0 psig to +250 psig	2	E
5.	Drywell Area Radiation (High Range)	2	F
6.	Primary Containment Isolation Valve Position	2 per penetration flow path[a][b]	E
7.	(Not used)		
8.	(Not used)		
9.	Suppression Pool Water Temperature	2[c]	E
10.	Drywell Temperature in Vicinity of Reactor Level Instrument Reference Leg	6	E
11.	Diesel Generator (DG) Parameters		
	a. Output Voltage	1 per DG	NA
	b. Output Current	1 per DG	NA
	c. Output Power	1 per DG	NA
	d. Battery Voltage	1 per DG	NA
12.	RHR Service Water Flow	2	E

(a) Not required for isolation valves whose associated penetration flow path is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

(b) Only one position indication channel is required for penetration flow paths with only one installed control room indication channel.

(c) Monitoring each of four quadrants.

3.6 CONTAINMENT SYSTEMS

3.6.3.1 (Not used)

(Not used)
3.6.3.1

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(Not Used)

(continued)

BASES

LCO (continued)

6. Primary Containment Isolation Valve (PCIV) Position

PCIV position is provided for verification of containment integrity. In the case of PCIV position, the important information is the isolation status of the containment penetration. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each active PCIV in a containment penetration flow path, i.e., two total channels of PCIV position indication for a penetration flow path with two active valves. For containment penetrations with only one active PCIV having control room indication, Note (b) requires a single channel of valve position indication to be OPERABLE. This is sufficient to redundantly verify the isolation status of each isolable penetration via indicated status of the active valve, as applicable, and prior knowledge of passive valve or system boundary status. If a penetration flow path is isolated, position indication for the PCIV(s) in the associated penetration flow path is not needed to determine status. Therefore, the position indication for valves in an isolated penetration flow path is not required to be OPERABLE. The indication for each PCIV consists of green and red indicator lights that illuminate to indicate whether the PCIV is fully open, fully closed, or in a mid-position. Therefore, the PAM specification deals specifically with this portion of the instrumentation channel.

(Not Used)

7., 8. ~~Drywell Hydrogen and Oxygen Concentration~~

~~Drywell hydrogen and oxygen analyzers are Type A instruments provided to detect high hydrogen or oxygen concentration conditions that represent a potential for containment breach. This variable is also important in verifying the adequacy of mitigating actions. High hydrogen and oxygen concentration is measured by two independent analyzers and continuously recorded on two recorders in the control room. The analyzers have the capability for sampling both the drywell and the torus. The available 0 – 10% range of these analyzers satisfies the criteria of RG 1.97. These recorders are the primary indication used by the operator during an accident. Therefore, the PAM specification deals specifically with this portion of the instrument channel.~~

9. Suppression Pool Water Temperature

Suppression pool water temperature is a Type A variable provided to detect a condition that could potentially lead to containment breach and to verify the effectiveness of ECCS actions taken to prevent containment breach. The suppression pool water temperature

(continued)

BASES

LCO
(continued)

6. Primary Containment Isolation Valve (PCIV) Position

PCIV position is provided for verification of containment integrity. In the case of PCIV position, the important information is the isolation status of the containment penetration. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each active PCIV in a containment penetration flow path, i.e., two total channels of PCIV position indication for a penetration flow path with two active valves. For containment penetrations with only one active PCIV having control room indication, Note (b) requires a single channel of valve position indication to be OPERABLE. This is sufficient to redundantly verify the isolation status of each isolable penetration via indicated status of the active valve, as applicable, and prior knowledge of passive valve or system boundary status. If a penetration flow path is isolated, position indication for the PCIV(s) in the associated penetration flow path is not needed to determine status. Therefore, the position indication for valves in an isolated penetration flow path is not required to be OPERABLE. The indication for each PCIV consists of green and red indicator lights that illuminate to indicate whether the PCIV is fully open, fully closed, or in a mid-position. Therefore, the PAM specification deals specifically with this portion of the instrumentation channel.

(Not Used)

7., 8. ~~Drywell Hydrogen and Oxygen Concentration~~

~~Drywell hydrogen and oxygen analyzers are Type A instruments provided to detect high hydrogen or oxygen concentration conditions that represent a potential for containment breach. This variable is also important in verifying the adequacy of mitigating actions. High hydrogen and oxygen concentration is measured by two independent analyzers and continuously recorded on two recorders in the control room. The analyzers have the capability for sampling both the drywell and the torus. The available 0 - 10% range of these analyzers satisfies the criteria of RG 1.97. These recorders are the primary indication used by the operator during an accident. Therefore, the PAM specification deals specifically with this portion of the instrument channel.~~

9. Suppression Pool Water Temperature

Suppression pool water temperature is a Type A variable provided to detect a condition that could potentially lead to containment breach and to verify the effectiveness of ECCS actions taken to prevent containment breach. The suppression pool water temperature

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.7 Reactor Building-to-Suppression Chamber Vacuum Breakers

BASES

BACKGROUND

The function of the reactor building-to-suppression chamber vacuum breakers is to relieve vacuum when primary containment depressurizes below reactor building pressure. If the drywell depressurizes below reactor building pressure, the negative differential pressure is mitigated by flow through the reactor building-to-suppression chamber vacuum breakers and through the suppression-chamber-to-drywell vacuum breakers. The design of the external (reactor building-to-suppression chamber) vacuum relief provisions consists of two vacuum breakers (a mechanical vacuum breaker and an air operated butterfly valve), located in series in each of two lines from the reactor building to the suppression chamber airspace. The butterfly valve is actuated by differential pressure. The mechanical vacuum breaker is self actuating and can be remotely operated for testing purposes. The two vacuum breakers in series must be closed to maintain a leak tight primary containment boundary.

A negative differential pressure across the drywell wall is caused by rapid depressurization of the drywell. Events that cause this rapid depressurization are cooling cycles, inadvertent primary containment spray actuation, and steam condensation in the event of a primary system rupture. Reactor building-to-suppression chamber vacuum breakers prevent an excessive negative differential pressure across the primary containment boundary. Cooling cycles result in minor pressure transients in the drywell, which occur slowly and are normally controlled by heating and ventilation equipment. Inadvertent spray actuation results in a more significant pressure transient and becomes important in sizing the external (reactor building-to-suppression chamber) vacuum breakers.

inerting/de-inerting of the primary containment.

Increased differential pressure between the reactor building and the drywell can also be caused by operations which remove gas from the drywell. Such operations include ~~functional testing of the primary containment hydrogen recombiners.~~

The external vacuum breakers are sized on the basis of the air flow from the secondary containment that is required to mitigate the depressurization transient and limit the maximum negative containment (drywell and suppression chamber) pressure to within design limits. The maximum depressurization rate is a function of the primary containment spray flow rate and temperature and the

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.8 Suppression Chamber-to-Drywell Vacuum Breakers

BASES

BACKGROUND

The function of the suppression chamber-to-drywell vacuum breakers is to relieve vacuum in the drywell. There are 12 internal vacuum breakers located on the vent header of the vent system between the drywell and the suppression chamber, which allow air and steam flow from the suppression chamber to the drywell when the drywell is at a negative pressure with respect to the suppression chamber. Therefore, suppression chamber-to-drywell vacuum breakers prevent an excessive negative differential pressure across the wetwell drywell boundary. Each vacuum breaker is a self actuating valve, similar to a check valve, which can be remotely operated for testing purposes.

A negative differential pressure across the drywell wall is caused by rapid depressurization of the drywell. Events that cause this rapid depressurization are cooling cycles, inadvertent drywell spray actuation, and steam condensation from sprays or subcooled water reflood of a break in the event of a primary system rupture. Cooling cycles result in minor pressure transients in the drywell that occur slowly and are normally controlled by heating and ventilation equipment. Spray actuation or spill of subcooled water out of a break results in more significant pressure transients and becomes important in sizing the internal vacuum breakers.

Increased differential pressure between the suppression chamber and the drywell can also be caused by operations which add gas to the suppression chamber or remove gas from the drywell. Such operations include ~~functional testing of the primary containment hydrogen recombiners~~ and inerting/de-inerting of the primary containment.

In the event of a primary system rupture, steam condensation within the drywell results in the most severe pressure transient. Following a primary system rupture, air in the drywell is purged into the suppression chamber free airspace, leaving the drywell full of steam. Subsequent condensation of the steam can be caused in two possible ways, namely, Emergency Core Cooling Systems flow from a recirculation line break, or drywell spray actuation following a loss of coolant accident (LOCA). These two cases cases determine the maximum depressurization rate of the drywell.

In addition, the waterleg in the Mark I Vent System downcomer is controlled by the drywell-to-suppression chamber differential

(continued)

(Not Used)

B 3.6 ~~CONTAINMENT SYSTEMS~~

(Not Used)

B 3.6.3.1 Primary Containment Hydrogen Recombiners

BASES

BACKGROUND

The primary containment hydrogen recombiner eliminates the potential breach of primary containment due to a hydrogen oxygen reaction and is part of combustible gas control required by 10 CFR 50.44, "Standards for Combustible Gas Control Systems in Light-Water-Cooled Reactors" (Ref. 1), and GDC 41, "Containment Atmosphere Cleanup" (Ref. 2). The primary containment hydrogen recombiner is required to reduce the hydrogen concentration in the primary containment following a loss of coolant accident (LOCA). The primary containment hydrogen recombiner accomplishes this by recombining hydrogen and oxygen to form water vapor. The vapor remains in the primary containment, thus eliminating any discharge to the environment. The primary containment hydrogen recombiner is manually initiated since flammability limits would not be reached until several days after a Design Basis Accident (DBA).

The primary containment hydrogen recombiner functions to maintain the hydrogen gas concentration within the containment at or below the flammability limit of 4.0 volume percent (v/o) following a postulated LOCA. It is fully redundant and consists of two 100% capacity subsystems. Each primary containment hydrogen recombiner consists of an enclosed blower assembly, heater section, reaction chamber, direct contact water spray gas cooler, water separator, and associated piping, valves, and instruments. The primary containment hydrogen recombiner will be manually initiated from the main control room when the hydrogen gas concentration in the primary containment reaches 3.3 v/o. When the primary containment is inerted (oxygen concentration < 4.0 v/o), the primary containment hydrogen recombiner will only function until the oxygen is used up (2.0 v/o hydrogen combines with 1.0 v/o oxygen). Two recombiners are provided to meet the requirement for redundancy and independence. Each recombiner is powered from a separate Engineered Safety Feature bus and is provided with separate power panel and control panel.

The process gas circulating through the heater, the reaction chamber, and the cooler is automatically regulated to 150 scfm by the use of an orifice plate installed in the cooler. The process gas is heated to approximately 1200°F. The hydrogen and oxygen gases are recombined into water vapor, which is then condensed in the water

(continued)

BASES

BACKGROUND (continued)

spray gas cooler by the associated residual heat removal subsystem and discharged with some of the effluent process gas to the suppression chamber. The majority of the cooled, effluent process gas is mixed with the incoming process gas to dilute the incoming gas prior to the mixture entering the heater section.

APPLICABLE SAFETY ANALYSES

The primary containment hydrogen recombiner provides the capability of controlling the bulk hydrogen concentration in primary containment to less than the lower flammable concentration of 4.0 v/o following a DBA. This control would prevent a primary containment wide hydrogen burn, thus ensuring that pressure and temperature conditions assumed in the analysis are not exceeded. The limiting DBA relative to hydrogen generation is a LOCA.

Hydrogen may accumulate in primary containment following a LOCA as a result of:

a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant; or

b. Radiolytic decomposition of water in the Reactor Coolant System.

To evaluate the potential for hydrogen accumulation in primary containment following a LOCA, the hydrogen generation is calculated as a function of time following the initiation of the accident. Assumptions recommended by Reference 3 are used to maximize the amount of hydrogen calculated.

The calculation confirms that when the mitigating systems are actuated in accordance with emergency procedures, the peak hydrogen concentration in the primary containment is < 4.0 v/o (Ref. 4).

The primary containment hydrogen recombiners satisfy Criterion 3 of the NRC Policy Statement (Ref. 5).

(continued)

BASES (continued)

LCO

Two primary containment hydrogen recombiners must be OPERABLE. This ensures operation of at least one primary containment hydrogen recombiner subsystem in the event of a worst case single active failure.

Operation with at least one primary containment hydrogen recombiner subsystem ensures that the post-LOCA hydrogen concentration can be prevented from exceeding the flammability limit.

APPLICABILITY

In MODES 1 and 2, the two primary containment hydrogen recombiners are required to control the hydrogen concentration within primary containment below its flammability limit of 4.0 v/o following a LOCA, assuming a worst case single failure.

In MODE 3, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in this MODE, the probability of an accident requiring the primary containment hydrogen recombiner is low. Therefore, the primary containment hydrogen recombiner is not required in MODE 3.

In MODES 4 and 5, the probability and consequences of a LOCA are low due to the pressure and temperature limitations in these MODES. Therefore, the primary containment hydrogen recombiner is not required in these MODES.

ACTIONS

A.1

With one primary containment hydrogen recombiner inoperable, the inoperable recombiner must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE recombiner is adequate to perform the hydrogen control function. However, the overall reliability is reduced because a single failure in the OPERABLE recombiner could result in reduced hydrogen control capability. The 30 day Completion Time is based on the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, the amount of time available after the event for operator action to prevent exceeding this limit, and the low probability of failure of the OPERABLE primary containment hydrogen recombiner.

(continued)

BASES

ACTIONS

A.1 (continued)

Required Action A.1 has been modified by a Note indicating that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one recombiner is inoperable. This allowance is provided because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, the low probability of the failure of the OPERABLE subsystem, and the amount of time available after a postulated LOCA for operator action to prevent exceeding the flammability limit.

B.1 and B.2

With two primary containment hydrogen recombiners inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by the Primary Containment Purge System or the Nitrogen Inerting System. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. In addition, the alternate hydrogen control system capability must be verified once per 12 hours thereafter to ensure its continued availability. Both the initial verification and all subsequent verifications may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two hydrogen recombiners inoperable for up to 7 days. Seven days is a reasonable time to allow two hydrogen recombiners to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit.

(continued)

BASES

ACTIONS (continued)

C.1

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1.1

Performance of a system functional test for each primary containment hydrogen recombiner ensures that the recombiners are OPERABLE and can attain and sustain the temperature necessary for hydrogen recombination. In particular, this SR verifies that the minimum heater sheath temperature increases to ≥ 1200°F in ≤ 1.5 hours and that it is maintained > 1150°F and < 1300°F for ≥ 4 hours thereafter to check the ability of the recombiner to function properly (and to make sure that significant heater elements are not burned out). The 24 month Frequency is based on a review of the surveillance test history and Reference 6.

SR 3.6.3.1.2

This SR ensures there are no physical problems that could affect recombiner operation. Since the recombiners are mechanically passive, except for the blower assemblies, they are subject to only minimal mechanical failure. The only credible failures involve loss of power or blower function, blockage of the internal flow path, missile impact, etc.

A visual inspection is sufficient to determine abnormal conditions that could cause such failures. The 24 month Frequency is based on a review of the surveillance test history and Reference 6.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.1.3

This SR requires performance of a resistance to ground test of each heater phase to make sure that there are no detectable grounds in any heater phase. This is accomplished by verifying that the resistance to ground for any heater phase is ≥ 1,000,000 ohms.

The 24 month Frequency is based on a review of the surveillance test history and Reference 6.

REFERENCES

1. 10 CFR 50.44.
2. 10 CFR 50, Appendix A, GDC 41.
3. Regulatory Guide 1.7, Revision 0, March 1971.
4. FSAR, Section 6.2.5.
5. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.
6. NRC Safety Evaluation Report for Amendment 174.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.2 Primary Containment Oxygen Concentration

BASES

BACKGROUND

Boiling water reactors must be designed to withstand events that generate hydrogen either due to the zirconium metal water reaction in the core or due to radiolysis. The primary method to control hydrogen is to inert the primary containment. With the primary containment inert, that is, oxygen concentration < 4.0 volume percent (v/o), a combustible mixture cannot be present in the primary containment for any hydrogen concentration. ~~The capability to inert the primary containment and maintain oxygen < 4.0 v/o works together with the Hydrogen Recombiner System (LCO 3.6.3.1, "Primary Containment Hydrogen Recombiners") and the Drywell Cooling System fans (LCO 3.6.3.2, "Drywell Cooling System Fans") to provide redundant and diverse methods to mitigate events that produce hydrogen. For example, an~~ event that rapidly generates hydrogen from zirconium metal water reaction will result in excessive hydrogen in primary containment, but oxygen concentration will remain < 4.0 v/o and no combustion can occur. ~~Long term generation of both hydrogen and oxygen from radiolytic decomposition of water may eventually result in a combustible mixture in primary containment, except that the hydrogen recombiners remove hydrogen and oxygen gases faster than they can be produced from radiolysis and again no combustion can occur.~~ This LCO ensures that oxygen concentration does not exceed 4.0 v/o during operation in the applicable conditions.

A

APPLICABLE SAFETY ANALYSES

The Plant Hatch Individual Plant Examination (Ref. 1) assumes that the primary containment is inerted when a Design Basis Accident loss of coolant accident occurs. Thus, the hydrogen assumed to be released to the primary containment as a result of metal water reaction in the reactor core will not produce combustible gas mixtures in the primary containment. ~~Oxygen, which is subsequently generated by radiolytic decomposition of water, is recombined by the hydrogen recombiners (LCO 3.6.3.1) more rapidly than it is produced.~~

The primary containment oxygen concentration satisfies Criterion 4 of the NRC Policy Statement (Ref. 2). It is assumed in Reference 1 and can be considered risk significant.

(continued)

(continued)

BASES

LCO (continued)

6. Primary Containment Isolation Valve (PCIV) Position

PCIV position is provided for verification of containment integrity. In the case of PCIV position, the important information is the isolation status of the containment penetration. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each active PCIV in a containment penetration flow path, i.e., two total channels of PCIV position indication for a penetration flow path with two active valves. For containment penetrations with only one active PCIV having control room indication, Note (b) requires a single channel of valve position indication to be OPERABLE. This is sufficient to redundantly verify the isolation status of each isolable penetration via indicated status of the active valve, as applicable, and prior knowledge of passive valve or system boundary status. If a penetration flow path is isolated, position indication for the PCIV(s) in the associated penetration flow path is not needed to determine status. Therefore, the position indication for valves in an isolated penetration flow path is not required to be OPERABLE. The indication for each PCIV consists of green and red indicator lights that illuminate to indicate whether the PCIV is fully open, fully closed, or in a mid-position. Therefore, the PAM specification deals specifically with this portion of the instrumentation channel.

7., 8. (Not used)

9. Suppression Pool Water Temperature

Suppression pool water temperature is a Type A variable provided to detect a condition that could potentially lead to containment breach and to verify the effectiveness of ECCS actions taken to prevent containment breach. The suppression pool water temperature

(continued)

BASES

LCO
(continued)

6. Primary Containment Isolation Valve (PCIV) Position

PCIV position is provided for verification of containment integrity. In the case of PCIV position, the important information is the isolation status of the containment penetration. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each active PCIV in a containment penetration flow path, i.e., two total channels of PCIV position indication for a penetration flow path with two active valves. For containment penetrations with only one active PCIV having control room indication, Note (b) requires a single channel of valve position indication to be OPERABLE. This is sufficient to redundantly verify the isolation status of each isolable penetration via indicated status of the active valve, as applicable, and prior knowledge of passive valve or system boundary status. If a penetration flow path is isolated, position indication for the PCIV(s) in the associated penetration flow path is not needed to determine status. Therefore, the position indication for valves in an isolated penetration flow path is not required to be OPERABLE. The indication for each PCIV consists of green and red indicator lights that illuminate to indicate whether the PCIV is fully open, fully closed, or in a mid-position. Therefore, the PAM specification deals specifically with this portion of the instrumentation channel.

7., 8. (Not used)

9. Suppression Pool Water Temperature

Suppression pool water temperature is a Type A variable provided to detect a condition that could potentially lead to containment breach and to verify the effectiveness of ECCS actions taken to prevent containment breach. The suppression pool water temperature

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.7 Reactor Building-to-Suppression Chamber Vacuum Breakers

BASES

BACKGROUND

The function of the reactor building-to-suppression chamber vacuum breakers is to relieve vacuum when primary containment depressurizes below reactor building pressure. If the drywell depressurizes below reactor building pressure, the negative differential pressure is mitigated by flow through the reactor building-to-suppression chamber vacuum breakers and through the suppression-chamber-to-drywell vacuum breakers. The design of the external (reactor building-to-suppression chamber) vacuum relief provisions consists of two vacuum breakers (a mechanical vacuum breaker and an air operated butterfly valve), located in series in each of two lines from the reactor building to the suppression chamber airspace. The butterfly valve is actuated by differential pressure. The mechanical vacuum breaker is self actuating and can be remotely operated for testing purposes. The two vacuum breakers in series must be closed to maintain a leak tight primary containment boundary.

A negative differential pressure across the drywell wall is caused by rapid depressurization of the drywell. Events that cause this rapid depressurization are cooling cycles, inadvertent primary containment spray actuation, and steam condensation in the event of a primary system rupture. Reactor building-to-suppression chamber vacuum breakers prevent an excessive negative differential pressure across the primary containment boundary. Cooling cycles result in minor pressure transients in the drywell, which occur slowly and are normally controlled by heating and ventilation equipment. Inadvertent spray actuation results in a more significant pressure transient and becomes important in sizing the external (reactor building-to-suppression chamber) vacuum breakers.

Increased differential pressure between the reactor building and the drywell can also be caused by operations which remove gas from the drywell. Such operations include inerting/de-inerting of the primary containment.

The external vacuum breakers are sized on the basis of the air flow from the secondary containment that is required to mitigate the depressurization transient and limit the maximum negative containment (drywell and suppression chamber) pressure to within design limits. The maximum depressurization rate is a function of the primary containment spray flow rate and temperature and the

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.8 Suppression Chamber-to-Drywell Vacuum Breakers

BASES

BACKGROUND

The function of the suppression chamber-to-drywell vacuum breakers is to relieve vacuum in the drywell. There are 12 internal vacuum breakers located on the vent header of the vent system between the drywell and the suppression chamber, which allow air and steam flow from the suppression chamber to the drywell when the drywell is at a negative pressure with respect to the suppression chamber. Therefore, suppression chamber-to-drywell vacuum breakers prevent an excessive negative differential pressure across the wetwell drywell boundary. Each vacuum breaker is a self actuating valve, similar to a check valve, which can be remotely operated for testing purposes.

A negative differential pressure across the drywell wall is caused by rapid depressurization of the drywell. Events that cause this rapid depressurization are cooling cycles, inadvertent drywell spray actuation, and steam condensation from sprays or subcooled water reflood of a break in the event of a primary system rupture. Cooling cycles result in minor pressure transients in the drywell that occur slowly and are normally controlled by heating and ventilation equipment. Spray actuation or spill of subcooled water out of a break results in more significant pressure transients and becomes important in sizing the internal vacuum breakers.

Increased differential pressure between the suppression chamber and the drywell can also be caused by operations which add gas to the suppression chamber or remove gas from the drywell. Such operations include inerting/de-inerting of the primary containment.

In the event of a primary system rupture, steam condensation within the drywell results in the most severe pressure transient. Following a primary system rupture, air in the drywell is purged into the suppression chamber free airspace, leaving the drywell full of steam. Subsequent condensation of the steam can be caused in two possible ways, namely, Emergency Core Cooling Systems flow from a recirculation line break, or drywell spray actuation following a loss of coolant accident (LOCA). These two cases cases determine the maximum depressurization rate of the drywell.

In addition, the waterleg in the Mark I Vent System downcomer is controlled by the drywell-to-suppression chamber differential

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.1 (Not used)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.2 Primary Containment Oxygen Concentration

BASES

BACKGROUND

Boiling water reactors must be designed to withstand events that generate hydrogen either due to the zirconium metal water reaction in the core or due to radiolysis. The primary method to control hydrogen is to inert the primary containment. With the primary containment inert, that is, oxygen concentration < 4.0 volume percent (v/o), a combustible mixture cannot be present in the primary containment for any hydrogen concentration. An event that rapidly generates hydrogen from zirconium metal water reaction will result in excessive hydrogen in primary containment, but oxygen concentration will remain < 4.0 v/o and no combustion can occur. This LCO ensures that oxygen concentration does not exceed 4.0 v/o during operation in the applicable conditions.

APPLICABLE SAFETY ANALYSES

The Plant Hatch Individual Plant Examination (Ref. 1) assumes that the primary containment is inerted when a Design Basis Accident loss of coolant accident occurs. Thus, the hydrogen assumed to be released to the primary containment as a result of metal water reaction in the reactor core will not produce combustible gas mixtures in the primary containment.

The primary containment oxygen concentration satisfies Criterion 4 of the NRC Policy Statement (Ref. 2). It is assumed in Reference 1 and can be considered risk significant.

LCO

The primary containment oxygen concentration is maintained < 4.0 v/o to ensure that an event that produces any amount of hydrogen does not result in a combustible mixture inside primary containment.

(continued)

BASES (continued)

APPLICABILITY

The primary containment oxygen concentration must be within the specified limit when primary containment is inerted, except as allowed by the relaxations during startup and shutdown addressed below. The primary containment must be inert in MODE 1, since this is the condition with the highest probability of an event that could produce hydrogen.

Inerting the primary containment is an operational problem because it prevents containment access without an appropriate breathing apparatus. Therefore, the primary containment is inerted as late as possible in the plant startup and de-inerted as soon as possible in the plant shutdown. As long as reactor power is < 15% RTP, the potential for an event that generates significant hydrogen is low and the primary containment need not be inert. Furthermore, the probability of an event that generates hydrogen occurring within the first 24 hours of a startup, or within the last 24 hours before a shutdown, is low enough that these "windows," when the primary containment is not inerted, are also justified. The 24 hour time period is a reasonable amount of time to allow plant personnel to perform inerting or de-inerting.

ACTIONS

A.1

If oxygen concentration is ≥ 4.0 v/o at any time while operating in MODE 1, with the exception of the relaxations allowed during startup and shutdown, oxygen concentration must be restored to < 4.0 v/o within 24 hours. The 24 hour Completion Time is allowed when oxygen concentration is ≥ 4.0 v/o because of the availability of other hydrogen mitigating systems (e.g., hydrogen recombiners) and the low probability and long duration of an event that would generate significant amounts of hydrogen occurring during this period.

B.1

If oxygen concentration cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, power must be reduced to ≤ 15% RTP within 8 hours. The 8 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.3.2.1

The primary containment (drywell and suppression chamber) must be determined to be inert by verifying that oxygen concentration is < 4.0 v/o. The 7 day Frequency is based on the slow rate at which oxygen concentration can change and on other indications of abnormal conditions (which would lead to more frequent checking by operators in accordance with plant procedures). Also, this Frequency has been shown to be acceptable through operating experience.

REFERENCES

1. Edwin I. Hatch Nuclear Plants Units 1 and 2 Plant Hatch Individual Plant Examination (IPE), December 1992.

2. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.3 Drywell Cooling System Fans

BASES

BACKGROUND

The Drywell Cooling System (air side) ensures a uniformly mixed post accident primary containment atmosphere, thereby minimizing the potential for local hydrogen burns due to a pocket of hydrogen above the flammable concentration.

The Drywell Cooling System is designed to withstand a loss of coolant accident (LOCA) in post accident environments without loss of function. However, the system is not "environmentally qualified." The system has eight subsystems consisting of recirculation fans, fan coil units, motors, controls, and ducting. However, due to the fact that the 2T47-B010A/B Units do not receive power from the diesel generators, they are not allowed to be used to meet the LCO requirements. Each of the six credited subsystems is sized to circulate 8000 scfm (for the 2T47-B007A/B fans) or 25,000 scfm (for the 2T47-B008A/B and 2T47-B009A/B fans). The Drywell Cooling System employs both forced circulation and natural circulation to ensure the proper mixing of hydrogen in primary containment. The recirculation fans provide the forced circulation to mix hydrogen while the fan coils provide the natural circulation by increasing the density through the cooling of the hot gases at the top of the drywell causing the cooled gases to gravitate to the bottom of the drywell. The six subsystems are initiated manually since flammability limits would not be reached until several days after a LOCA. Three of the subsystems are powered from one emergency power supply while the other three subsystems are powered from another emergency power supply. Since each subsystem can provide 100% of the mixing requirements, the system will provide its design function with a worst case single active failure.

The Drywell Cooling System uses the Drywell Cooling System recirculating fans to mix the drywell atmosphere. The fan coil units and recirculation fans are automatically disengaged during a LOCA but may be restored to service manually by the operator. In the event of a loss of offsite power, all fan coil units, recirculating fans, and primary containment water chillers are transferred to the emergency diesels. The fan coil units and recirculating fans are started automatically from diesel power upon loss of offsite power.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The Drywell Cooling System fans provide the capability for reducing the local hydrogen concentration to approximately the bulk average concentration following a Design Basis Accident (DBA). The limiting DBA relative to hydrogen generation is a LOCA.

Hydrogen may accumulate in primary containment following a LOCA as a result of:

a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant; or

b. Radiolytic decomposition of water in the Reactor Coolant System.

To evaluate the potential for hydrogen accumulation in primary containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Conservative assumptions recommended by Reference 1 are used to maximize the amount of hydrogen calculated.

The Reference 2 calculations show that hydrogen assumed to be released to the drywell within 2 minutes following a DBA LOCA raises drywell hydrogen concentration to over 2.5 volume percent (v/o). Natural circulation phenomena result in a gradient concentration difference of less then 0.5 v/o in the drywell and less than 0.1 v/o in the suppression chamber. Even though this gradient is acceptably small and no credit for mechanical mixing was assumed in the analysis, two Drywell Cooling System fans are required to be OPERABLE by this LCO. This will ensure the gradient concentration difference is small.

The Drywell Cooling System fans satisfy Criterion 3 of the NRC Policy Statement (Ref. 3).

LCO

Two Drywell Cooling System fans must be OPERABLE to ensure operation of at least one fan in the event of a worst case single active failure. Each of these fans must be powered from an independent safety related bus. The 2T47-B007A and B, B008 A and B, and B009 A and B fans shall be used to meet this requirement. In addition, only the recirculation fan portion of the system must be OPERABLE; the cooler portion does not need to be OPERABLE. Operation with at

(continued)

BASES

LCO (continued)

least one fan provides the capability of controlling the bulk hydrogen concentration in primary containment without exceeding the flammability limit.

APPLICABILITY

In MODES 1 and 2, the two Drywell Cooling System fans ensure the capability to prevent localized hydrogen concentrations above the flammability limit of 4.0 v/o in drywell, assuming a worst case single active failure.

In MODE 3, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in this MODE, the probability of an accident requiring the Drywell Cooling System fans is low. Therefore, the Drywell Cooling System fans are not required in MODE 3.

In MODES 4 and 5, the probability and consequences of a LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, the Drywell Cooling System fans are not required in these MODES.

ACTIONS

A.1

With one required Drywell Cooling System fan inoperable, the inoperable fan must be restored to OPERABLE status within 30 days. In this condition, the remaining OPERABLE fan is adequate to perform the hydrogen mixing function. However, the overall reliability is reduced because a single failure in the OPERABLE fan could result in reduced hydrogen mixing capability. The 30 day Completion Time is based on the availability of the second fan, the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, the amount of time available after the event for operator action to prevent exceeding this limit, and the availability of natural circulation to maintain the atmosphere mixed.

(continued)

BASES

ACTIONS

A.1 (continued)

Required Action A.1 has been modified by a Note indicating that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one required Drywell Cooling System fan is inoperable. This allowance is provided because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, the low probability of the failure of the OPERABLE fan, and the amount of time available after a postulated LOCA for operator action to prevent exceeding the flammability limit.

B.1

With two Drywell Cooling System fans inoperable, one fan must be restored to OPERABLE status within 7 days. Seven days is a reasonable time to allow two Drywell Cooling System fans to be inoperable because the hydrogen mixing function is maintained via natural circulation and because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit.

C.1

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.3.1

Operating each required Drywell Cooling System fan for ≥ 15 minutes ensures that each subsystem is OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.3.1 (continued)

The 92 day Frequency is consistent with the Inservice Testing Program Frequencies, operating experience, the known reliability of the fan motors and controls, and the two redundant fans available.

REFERENCES

1. Regulatory Guide 1.7, Revision 0.

2. FSAR, Section 6.2.5.

3. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.1 Secondary Containment

BASES

BACKGROUND

The function of the secondary containment is to contain, dilute, and hold up fission products that may leak from primary containment following a Design Basis Accident (DBA). In conjunction with operation of the Standby Gas Treatment (SGT) System and closure of certain valves whose lines penetrate the secondary containment, the secondary containment is designed to reduce the activity level of the fission products prior to release to the environment and to isolate and contain fission products that are released during certain operations that take place inside primary containment, when primary containment is not required to be OPERABLE, or that take place outside primary containment.

The secondary containment is a structure that completely encloses the primary containment and those components that may be postulated to contain primary system fluid. This structure forms a control volume that serves to hold up and dilute the fission products. It is possible for the pressure in the control volume to rise relative to the environmental pressure (e.g., due to pump and motor heat load additions). The secondary containment encompasses three separate zones: the Unit 1 reactor building (Zone I), the Unit 2 reactor building (Zone II), and the common refueling floor (Zone III). The secondary containment can be modified to exclude the Unit 1 reactor building (Zone I) provided the following requirements are met:

a. Unit 1 Technical Specifications do not require OPERABILITY of Zone I;

b. All hatches separating Zone III from Zone I are closed and sealed; and

c. At least one door in each access path separating Zone III from Zone I is closed.

Similarly, other zones can be excluded from the secondary containment OPERABILITY requirement during various plant operating conditions with the appropriate controls. For example, during Unit 2 shutdown operations, the secondary containment can be modified to exclude the Unit 2 reactor building (Zone II) (either alone or in combination with excluding Zone I as described above) provided the following requirements are met:

(continued)

BASES

BACKGROUND (continued)

a. Unit 2 is not conducting operations with a potential for draining the reactor vessel (OPDRV);

b. All hatches separating Zone III from Zone II are closed and sealed; and

c. At least one door in each access path separating Zone III from Zone II is closed.

To prevent ground level exfiltration while allowing the secondary containment to be designed as a conventional structure, the secondary containment requires support systems to maintain the control volume pressure at less than the external pressure. Requirements for these systems are specified separately in LCO 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)," and LCO 3.6.4.3, "Standby Gas Treatment (SGT) System." When one or more zones are excluded from secondary containment, the specific requirements for the support systems will also change (e.g., securing particular SGT or drain isolation valves).

APPLICABLE SAFETY ANALYSES

There are two principal accidents for which credit is taken for secondary containment OPERABILITY. These are a loss of coolant accident (LOCA) (Ref. 1) and a fuel handling accident inside secondary containment (Ref. 2). The secondary containment performs no active function in response to either of these limiting events; however, its leak tightness is required to ensure that the release of radioactive materials from the primary containment is restricted to those leakage paths and associated leakage rates assumed in the accident analysis and that fission products entrapped within the secondary containment structure will be treated by the Unit 1 and Unit 2 SGT Systems prior to discharge to the environment. Postulated LOCA leakage paths from the primary containment into secondary containment include those into both the reactor building and refueling floor zones (e.g., drywell head leakage).

Secondary containment satisfies Criterion 3 of the NRC Policy Statement (Ref. 4).

LCO

An OPERABLE secondary containment provides a control volume into which fission products that bypass or leak from primary containment, or are released from the reactor coolant pressure boundary

(continued)

BASES

LCO (continued)

components located in secondary containment, can be diluted and processed prior to release to the environment. For the secondary containment to be considered OPERABLE, it must have adequate leak tightness to ensure that the required vacuum (0.20 inch of vacuum) can be established and maintained. The secondary containment boundary required to be OPERABLE is dependent on the operating status of both units, as well as the configuration of doors, hatches, refueling floor plugs, SCIVs, and available flow paths to SGT Systems. The required boundary encompasses the zones which can be postulated to contain fission products from accidents required to be considered for the condition of each unit, and furthermore, must include zones not isolated from the SGT subsystems being credited for meeting LCO 3.6.4.3. Allowed configurations, associated SGT subsystem requirements, and associated SCIV requirements are detailed in the Technical Requirements Manual (Ref. 3).

APPLICABILITY

In MODES 1, 2, and 3, a LOCA could lead to a fission product release to primary containment that leaks to secondary containment (the reactor building zone and potentially the refueling floor zone). Therefore, secondary containment OPERABILITY is required during the same operating conditions that require primary containment OPERABILITY.

In MODES 4 and 5, the probability and consequences of the LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining secondary containment OPERABLE is not required in MODE 4 or 5 to ensure a control volume, except for other situations for which significant releases of radioactive material can be postulated, such as during OPDRVs, during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the secondary containment. (Note, moving irradiated fuel assemblies in the secondary containment may also occur in MODES 1, 2, and 3.) Since CORE ALTERATIONS and movement of irradiated fuel assemblies are only postulated to release radioactive material to the refueling floor zone, the secondary containment configuration may consist of only Zone III during these conditions. Similarly, during OPDRVs while in MODE 4 (vessel head bolted) the release of radioactive materials is only postulated to the associated reactor building, the secondary containment configuration may consist of only Zone II.

(continued)

BASES (continued)

ACTIONS

A.1

If secondary containment is inoperable, it must be restored to OPERABLE status within 4 hours. The 4 hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of maintaining secondary containment during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring secondary containment OPERABILITY) occurring during periods where secondary containment is inoperable is minimal.

B.1 and B.2

If secondary containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1, C.2, and C.3

Movement of irradiated fuel assemblies in the secondary containment, CORE ALTERATIONS, and OPDRVs can be postulated to cause fission product release to the secondary containment. In such cases, the secondary containment is the only barrier to release of fission products to the environment. CORE ALTERATIONS and movement of irradiated fuel assemblies must be immediately suspended if the secondary containment is inoperable.

Suspension of these activities shall not preclude completing an action that involves moving a component to a safe position. Also, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action C.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case,

(continued)

BASES

ACTIONS

C.1, C.2, and C.3 (continued)

inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1 and SR 3.6.4.1.2

Verifying that secondary containment equipment hatches and one access door in each access opening are closed ensures that the infiltration of outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur. Verifying that all such openings are closed provides adequate assurance that exfiltration from the secondary containment will not occur. SR 3.6.4.1.1 also requires equipment hatches to be sealed. In this application, the term "sealed" has no connotation of leak tightness. Maintaining secondary containment OPERABILITY requires verifying one door in the access opening is closed. An access opening contains one inner and one outer door. The intent is not to breach the secondary containment at any time when secondary containment is required. This is achieved by maintaining the inner or outer portion of the barrier closed at all times. However, all secondary containment access doors are normally kept closed, except when the access opening is being used for entry and exit or when maintenance is being performed on an access opening. When the secondary containment configuration excludes Zone I and/or Zone II, these SRs also include verifying the hatches and doors separating the common refueling floor zone from the reactor building(s). The 31 day Frequency for these SRs has been shown to be adequate, based on operating experience, and is considered adequate in view of the other indications of door and hatch status that are available to the operator.

SR 3.6.4.1.3 and SR 3.6.4.1.4

The Unit 1 and Unit 2 SGT Systems exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. To ensure that all fission products are treated, SR 3.6.4.1.3 verifies that the appropriate SGT System(s) will rapidly establish and maintain a negative pressure in the secondary containment. This is confirmed by demonstrating that the required SGT subsystem(s) will draw down the secondary containment to ≥ 0.20 inch of vacuum water gauge in ≤ 120 seconds. This cannot be accomplished if the secondary containment boundary is not intact. SR 3.6.4.1.4 demonstrates that the required SGT subsystem(s) can

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.3 and SR 3.6.4.1.4 (continued)

maintain ≥ 0.20 inch of vacuum water gauge for 1 hour at a flow rate ≤ 4000 cfm for each SGT subsystem. The 1 hour test period allows secondary containment to be in thermal equilibrium at steady state conditions. Therefore, these two tests are used to ensure secondary containment boundary integrity. Since these SRs are secondary containment tests, they need not be performed with each SGT subsystem. The SGT subsystems are tested on a STAGGERED TEST BASIS, however, to ensure that in addition to the requirements of LCO 3.6.4.3, each SGT subsystem or combination of subsystems will perform this test. The number of SGT subsystems and the required combinations are dependent on the configuration of the secondary containment and are detailed in the Technical Requirements Manual (Ref. 3). The Note to SR 3.6.4.1.3 and SR 3.6.4.1.4 specifies that the number of required SGT subsystems be one less than the number required to meet LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," for the given configuration. The 24 month Frequency, on a STAGGERED TEST BASIS, of SRs 3.6.4.1.3 and 3.6.4.1.4 is also based on a review of the surveillance test history and Reference 5.

REFERENCES

1. FSAR, Section 15.1.39.

2. FSAR, Section 15.1.41.

3. Technical Requirements Manual.

4. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.

5. NRC Safety Evaluation Report for Amendment 174.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.2 Secondary Containment Isolation Valves (SCIVs)

BASES

BACKGROUND

The function of the SCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs). Secondary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that fission products that leak from primary containment following a DBA, or that are released during certain operations when primary containment is not required to be OPERABLE or take place outside primary containment, are maintained within the secondary containment boundary.

The OPERABILITY requirements for SCIVs help ensure that an adequate secondary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. These isolation devices consist of either passive devices or active (automatic) devices. Manual valves, de-activated automatic valves secured in their closed position, check valves with flow through the valve secured, and blind flanges are considered passive devices.

Automatic SCIVs close on a secondary containment isolation signal to establish a boundary for untreated radioactive material within secondary containment following a DBA or other accidents.

Other penetrations are isolated by the use of valves in the closed position or blind flanges.

APPLICABLE SAFETY ANALYSES

The SCIVs must be OPERABLE to ensure the secondary containment barrier to fission product releases is established. The principal accidents for which the secondary containment boundary is required are a loss of coolant accident (Ref. 1) and a fuel handling accident inside secondary containment (Ref. 2). The secondary containment performs no active function in response to either of these limiting events, but the boundary established by SCIVs is required to ensure that leakage from primary containment is processed by the Standby Gas Treatment (SGT) System before being released to the environment.

Maintaining SCIVs OPERABLE with isolation times within limits ensures that fission products will remain trapped inside secondary

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

containment so that they can be treated by the SGT System prior to discharge to the environment.

SCIVs satisfy Criterion 3 of the NRC Policy Statement (Ref. 4).

LCO

SCIVs form a part of the secondary containment boundary. The SCIV safety function is related to control of offsite radiation releases resulting from DBAs.

The power operated isolation valves are considered OPERABLE when their isolation times are within limits and the valves actuate on an automatic isolation signal. The valves covered by this LCO, along with their associated stroke times, are listed in Reference 3.

The normally closed isolation valves or blind flanges are considered OPERABLE when manual valves are closed, or open in accordance with appropriate administrative controls, automatic SCIVs are de-activated and secured in their closed position, and blind flanges are in place. These passive isolation valves or devices are listed in Reference 3.

The SCIVs required to be OPERABLE are dependent on the configuration of the secondary containment (which is dependent on the operating status of both units, as well as the configuration of doors, hatches, refueling floor plugs, and available flow paths to SGT Systems). The required boundary encompasses the zones which can be postulated to contain fission products from accidents required to be considered for the condition of each unit, and furthermore, must include zones not isolated from the SGT subsystems being credited for meeting LCO 3.6.4.3, "Standby Gas Treatment (SGT) System." The required SCIVs are those in penetrations communicating with the zones required for secondary containment OPERABILITY and are detailed in Reference 3.

APPLICABILITY

In MODES 1, 2, and 3, a LOCA could lead to a fission product release to the primary containment that leaks to the secondary containment. Therefore, the OPERABILITY of SCIVs is required.

In MODES 4 and 5, the probability and consequences of a LOCA are reduced due to pressure and temperature limitations in these MODES. Therefore, maintaining SCIVs OPERABLE is not required in

(continued)

BASES

APPLICABILITY (continued)

MODE 4 or 5, except for other situations under which significant radioactive releases can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the secondary containment. (Note: Moving irradiated fuel assemblies in the secondary containment may also occur in MODES 1, 2, and 3.)

ACTIONS

The ACTIONS are modified by three Notes. The first Note allows penetration flow paths to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated.

The second Note provides clarification that for the purpose of this LCO separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable SCIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable SCIVs are governed by subsequent Condition entry and application of associated Required Actions.

The third Note ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable SCIV.

A.1 and A.2

In the event that there are one or more penetration flow paths with one SCIV inoperable, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic SCIV, a closed manual valve, and a blind flange. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available device to secondary containment. The Required Action must be completed within the 8 hour Completion Time. The specified time period is reasonable considering the time required to

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

isolate the penetration, and the probability of a DBA, which requires the SCIVs to close, occurring during this short time is very low.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that secondary containment penetrations required to be isolated following an accident, but no longer capable of being automatically isolated, will be in the isolation position should an event occur. The Completion Time of once per 31 days is appropriate because the isolation devices are operated under administrative controls and the probability of their misalignment is low. This Required Action does not require any testing or device manipulation. Rather, it involves verification that the affected penetration remains isolated.

Required Action A.2 is modified by a Note that applies to devices located in high radiation areas and allows them to be verified closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment once they have been verified to be in the proper position, is low.

B.1

With two SCIVs in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 4 hours. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 4 hour Completion Time is reasonable considering the time required to isolate the penetration and the probability of a DBA, which requires the SCIVs to close, occurring during this short time, is very low.

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are

(continued)

BASES

ACTIONS

C.1, and C.2 (continued)

reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1, D.2, and D.3

If any Required Action and associated Completion Time of Condition A or B are not met, the plant must be placed in a condition in which the LCO does not apply. If applicable, CORE ALTERATIONS and the movement of irradiated fuel assemblies in the secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be immediately initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action D.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving fuel while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations.

Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1

This SR verifies that each secondary containment manual isolation valve and blind flange that is required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the secondary containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those isolation devices in secondary containment that are capable of being mispositioned are in the correct position.

Since these isolation devices are readily accessible to personnel during normal operation and verification of their position is relatively

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1 (continued)

easy, the 31 day Frequency was chosen to provide added assurance that the isolation devices are in the correct positions.

Two Notes have been added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these isolation devices, once they have been verified to be in the proper position, is low.

A second Note has been included to clarify that SCIVs that are open under administrative controls are not required to meet the SR during the time the SCIVs are open.

SR 3.6.4.2.2

Verifying that the isolation time of each power operated and each automatic SCIV is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that the SCIV will isolate in a time period less than or equal to that assumed in the safety analyses. The Frequency of this SR was developed based upon engineering judgment and the similarity to PCIVs.

SR 3.6.4.2.3

Verifying that each automatic SCIV closes on a secondary containment isolation signal is required to prevent leakage of radioactive material from secondary containment following a DBA or other accidents. This SR ensures that each automatic SCIV will actuate to the isolation position on a secondary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.2.5 overlaps this SR to provide complete testing of the safety function. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The 24 month Frequency is based on a review of the surveillance test history and Reference 5.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Section 15.1.39.

2. FSAR, Section 15.1.41.

3. Technical Requirements Manual.

4. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.

5. NRC Safety Evaluation Report for Amendment 174.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.3 Standby Gas Treatment (SGT) System

BASES

BACKGROUND

The SGT System is required by 10 CFR 50, Appendix A, GDC 41, "Containment Atmosphere Cleanup" (Ref. 1). The function of the SGT System is to ensure that radioactive materials that leak from the primary containment into the secondary containment following a Design Basis Accident (DBA) are filtered and adsorbed prior to exhausting to the environment.

The Unit 1 and Unit 2 SGT Systems each consists of two fully redundant subsystems, each with its own set of dampers, charcoal filter train, and controls. The Unit 1 SGT subsystems' ductwork is separate from the inlet to the filter train to the discharge of the fan. The rest of the ductwork is common. The Unit 2 SGT subsystems' ductwork is separate except for the suction from the drywell and torus, which is common (however, this suction path is not required for subsystem OPERABILITY).

Each charcoal filter train consists of (components listed in order of the direction of the air flow):

a. A demister or moisture separator;

b. An electric heater;

c. A prefilter;

d. A high efficiency particulate air (HEPA) filter;

e. Two charcoal adsorbers for Unit 1 subsystems and one charcoal adsorber for Unit 2 subsystems;

f. A second HEPA filter; and

g. An axial vane fan for Unit 1 subsystems and a centrifugal fan for Unit 2 subsystems.

The sizing of the SGT Systems equipment and components is based on the results of an infiltration analysis, as well as an exfiltration analysis of the secondary containment. The internal pressure of the SGT Systems boundary region is maintained at a negative pressure when the system is in operation, to conservatively ensure zero

(continued)

BASES

BACKGROUND (continued)

exfiltration of air from the building when exposed to winds as high as 31 mph.

The demister is provided to remove entrained water in the air, while the electric heater reduces the relative humidity of the airstream to < 70% (Refs. 2 and 3). The prefilter removes large particulate matter, while the HEPA filter removes fine particulate matter and protects the charcoal from fouling. The charcoal adsorbers remove gaseous elemental iodine and organic iodides, and the final HEPA filter collects any carbon fines exhausted from the charcoal adsorber.

The Unit 1 and Unit 2 SGT Systems automatically start and operate in response to actuation signals indicative of conditions or an accident that could require operation of the system. Following initiation, all required charcoal filter train fans start. Upon verification that the required subsystems are operating, the redundant required subsystem is normally shut down.

APPLICABLE SAFETY ANALYSES

The design basis for the Unit 1 and Unit 2 SGT Systems is to mitigate the consequences of a loss of coolant accident and fuel handling accidents (Refs. 2, 3, 4, and 5). For all events analyzed, the SGT Systems are shown to be automatically initiated to reduce, via filtration and adsorption, the radioactive material released to the environment.

The SGT System satisfies Criterion 3 of the NRC Policy Statement (Ref. 7).

LCO

Following a DBA, a minimum number of SGT subsystems are required to maintain the secondary containment at a negative pressure with respect to the environment and to process gaseous releases. Meeting the LCO requirements for OPERABLE subsystems ensures operation of the minimum number of SGT subsystems in the event of a single active failure. The required number of SGT subsystems is dependent on the configuration required to meet LCO 3.6.4.1, "Secondary Containment." For secondary containment OPERABILITY consisting of all three zones, the required number of SGT subsystems is four. With secondary containment OPERABILITY consisting of one reactor building and the common refueling floor zones, the required number of SGT subsystem is three. Allowed

(continued)

BASES

LCO (continued)

configurations and associated SGT subsystem requirements are detailed in the Technical Requirements Manual (Ref. 6).

In addition, with secondary containment in modified configurations, the SGT System valves to excluded zone(s) are not included as part of SGT System OPERABILITY (i.e., the valves may be secured closed and are not required to open on an actuation signal).

APPLICABILITY

In MODES 1, 2, and 3, a LOCA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, Unit 1 and Unit 2 SGT Systems OPERABILITY are required during these MODES.

In MODES 4 and 5, the probability and consequences of a LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the SGT Systems in OPERABLE status is not required in MODE 4 or 5, except for other situations under which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the secondary containment.

ACTIONS

The Actions are modified by a Note to indicate that when both Unit 1 SGT subsystems are placed in an inoperable status for inspection of the Unit 1 hardened vent rupture disk, entry into associated Conditions and Required Actions may be delayed for up to 24 hours, provided both Unit 2 SGT subsystems are OPERABLE. Upon completion of the inspection or expiration of the 24 hour allowance, the Unit 1 SGT subsystems must be returned to OPERABLE status or the applicable Conditions entered and Required Actions taken. The 24 hour allowance is based upon precluding a dual unit shutdown to perform the inspection, yet minimizing the time both Unit 1 SGT subsystems are inoperable.

A.1 and B.1

With one required Unit 1 or Unit 2 SGT subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status. In this condition, the remaining required OPERABLE SGT subsystems are adequate to perform the required radioactivity release control function. However, the overall system reliability is reduced because a single

(continued)

BASES

ACTIONS

A.1 and B.1 (continued)

failure in one of the remaining required OPERABLE subsystems could result in the radioactivity release control function not being adequately performed. The 7 and 30 day Completion Times are based on consideration of such factors as the availability of the OPERABLE redundant SGT subsystems and the low probability of a DBA occurring during this period. Additionally, the 30 day Completion Time of Required Action A.1 is based on three remaining OPERABLE SGT subsystems, of which two are Unit 2 subsystems, and the secondary containment volume in the Unit 1 reactor building being open to the common refueling floor where the two Unit 2 SGT subsystems can readily provide rapid drawdown of vacuum. Testing and analysis has shown that in this configuration, even with an additional single failure (which is not necessary to assume while in ACTIONS) the secondary containment volume may be drawn to a vacuum in the time required to support assumptions of analyses.

C.1 and C.2

If the SGT subsystem cannot be restored to OPERABLE status within the required Completion Time in MODE 1, 2, or 3, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

In the event that a Unit 1 SGT subsystem is the one not restored to OPERABLE status as required by Required Action A.1 or B.1, and:

1. All three zones are required for secondary containment OPERABILITY; and

2. Unit 1 is shutdown with its Technical Specifications not requiring secondary containment OPERABILITY (i.e., not handling irradiated fuel, performing CORE ALTERATIONS, or conducting OPDRV),

operation of Unit 2 can continue provided that the Unit 1 reactor building zone is isolated from the remainder of secondary containment and the SGT System. In this modified secondary containment configuration, only three SGT subsystems are required to be OPERABLE to meet LCO 3.6.4.3, and no limitation is applied to

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

the inoperable Unit 1 SGT subsystem. This in effect is an alternative to restoring the inoperable Unit 1 SGT subsystem, i.e., shut down Unit 1 and isolate its reactor building zone from secondary containment and SGT System.

D.1, D.2.1, D.2.2, and D.2.3

During movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, when Required Action A.1 or B.1 cannot be completed within the required Completion Time, the remaining required OPERABLE SGT subsystems should immediately be placed in operation. This action ensures that the remaining subsystems are OPERABLE, that no failures that could prevent automatic actuation have occurred, and that any other failure would be readily detected.

An alternative to Required Action D.1 is to immediately suspend activities that represent a potential for releasing radioactive material to the secondary containment, thus placing the plant in a condition that minimizes risk. If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies must immediately be suspended. Suspension of these activities must not preclude completion of movement of a component to a safe position. Also, if applicable, actions must immediately be initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

The Required Actions of Condition D have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

E.1

If two or more required SGT subsystems are inoperable in MODE 1, 2 or 3, the Unit 1 and Unit 2 SGT Systems may not be capable of supporting the required radioactivity release control function. Therefore, LCO 3.0.3 must be entered immediately.

(continued)

BASES

ACTIONS (continued)

F.1, F.2, and F.3

When two or more required SGT subsystems are inoperable, if applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in secondary containment must immediately be suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must immediately be initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action F.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating each required Unit 1 and Unit 2 SGT subsystem for ≥ 10 continuous hours ensures that they are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters on for ≥ 10 continuous hours every 31 days eliminates moisture on the adsorbers and HEPA filters. The 31 day Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system.

SR 3.6.4.3.2

This SR verifies that the required Unit 1 and Unit 2 SGT filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

(continued)

Enclosure 3

Edwin I. Hatch Nuclear Plant
Joseph M. Farley Nuclear Plant
Vogtle Electric Generating Plant
Application for Technical Specification Amendment to
Eliminate Requirements for Hydrogen Recombiners and Hydrogen and Oxygen Monitors
Using the Consolidated Line Item Improvement Process

FNP Marked-up and Clean Typed TS and Bases Pages

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DELETED

3.3 INSTRUMENTATION

3.3.3 Post Accident Monitoring (PAM) Instrumentation

LCO 3.3.3 The PAM instrumentation for each Function in Table 3.3.3-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

----------NOTES----------

1. LCO 3.0.4 is not applicable.
2. Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required channel inoperable.	A.1 Restore required channel to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action in accordance with Specification 5.6.8.	Immediately
C. ~~----------NOTE---------- Not applicable to hydrogen monitor channels. ----------~~ One or more Functions with two required channels inoperable.	C.1 Restore one channel to OPERABLE status.	7 days

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~D. Two hydrogen monitor channels inoperable.~~	~~D.1 Restore one hydrogen monitor channel to OPERABLE status~~	~~72 hours~~
~~E.~~ Required Action and associated Completion Time of Condition C ~~or D~~ not met.	~~E.1~~ Enter the Condition referenced in Table 3.3.3-1 for the channel.	Immediately
~~F.~~ As required by Required Action ~~E.~~1 and referenced in Table 3.3.3-1.	~~F.~~1 Be in MODE 3. AND ~~F.~~2 Be in MODE 4.	6 hours 12 hours
~~G.~~ As required by Required Action ~~E.~~1 and referenced in Table 3.3.3-1.	~~G.~~1 Initiate action in accordance with Specification 5.6.8.	Immediately

D

E

D

F

SURVEILLANCE REQUIREMENTS

----------NOTE----------
SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1.

SURVEILLANCE		FREQUENCY
SR 3.3.3.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
SR 3.3.3.2	Perform CHANNEL CALIBRATION.	18 months

Table 3.3.3-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

FUNCTION	REQUIRED CHANNELS	CONDITION REFERENCED FROM REQUIRED ACTION ~~E~~ 1
1. RCS Hot Leg Temperature (Wide Range)	2	~~F~~
2. RCS Cold Leg Temperature (Wide Range)	2	~~F~~
3. RCS Pressure (Wide Range)	2	~~F~~
4. Steam Generator (SG) Water Level (Wide or Narrow Range)	2/SG	~~F~~
5. Refueling Water Storage Tank Level	2	~~F~~
6. Containment Pressure (Narrow Range)	2	~~F~~
7. Pressurizer Water Level	2	~~F~~
8. Steam Line Pressure	2/SG	~~F~~
9. Auxiliary Feedwater Flow Rate	2	~~F~~
10. RCS Subcooling Margin Monitor	2	~~F~~
11. Containment Water Level (Wide Range)	2	~~F~~
12. Core Exit Temperature - Quadrant 1	2[a]	~~F~~
13. Core Exit Temperature - Quadrant 2	2[a]	~~F~~
14. Core Exit Temperature - Quadrant 3	2[a]	~~F~~
15. Core Exit Temperature - Quadrant 4	2[a]	~~F~~
16. Reactor Vessel Level Indicating System	2	~~G~~
17. Condensate Storage Tank Level	2	~~F~~
18. ~~Hydrogen Monitors~~	~~2~~	~~F~~
19. Containment Area Radiation (High Range)	2	~~G~~

(a) A channel consists of two core exit thermocouples.

D

E

F

DELETED

DELETED

3.6 CONTAINMENT SYSTEMS

3.6.7 Hydrogen Recombiners

LCO 3.6.7 Two hydrogen recombiners shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One hydrogen recombiner inoperable.	A.1	----------NOTE---------- LCO 3.0.4 is not applicable. ---------- Restore hydrogen recombiner to OPERABLE status.	30 days
B. Two hydrogen recombiners inoperable.	B.1	Verify by administrative means that the hydrogen control function is maintained.	1 hour AND Once per 12 hours thereafter
	AND		
	B.2	Restore one hydrogen recombiner to OPERABLE status.	7 days
C. Required Action and associated Completion Time not met.	C.1	Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.6.7.1	Perform a system functional test for each hydrogen recombiner.	18 months
SR 3.6.7.2	Visually examine each hydrogen recombiner enclosure and verify there is no evidence of abnormal conditions.	18 months
SR 3.6.7.3	Perform a resistance to ground test for each heater phase.	18 months

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3.3 INSTRUMENTATION

3.3.3 Post Accident Monitoring (PAM) Instrumentation

LCO 3.3.3 The PAM instrumentation for each Function in Table 3.3.3-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

----------NOTES----------

1. LCO 3.0.4 is not applicable.

2. Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required channel inoperable.	A.1 Restore required channel to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action in accordance with Specification 5.6.8.	Immediately
C. One or more Functions with two required channels inoperable.	C.1 Restore one channel to OPERABLE status.	7 days

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition C not met.	D.1 Enter the Condition referenced in Table 3.3.3-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.3-1.	E.1 Be in MODE 3. AND E.2 Be in MODE 4.	6 hours 12 hours
F. As required by Required Action D.1 and referenced in Table 3.3.3-1.	F.1 Initiate action in accordance with Specification 5.6.8.	Immediately

SURVEILLANCE REQUIREMENTS

----------NOTE----------
SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1.

SURVEILLANCE		FREQUENCY
SR 3.3.3.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
SR 3.3.3.2	Perform CHANNEL CALIBRATION.	18 months

Table 3.3.3-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

FUNCTION	REQUIRED CHANNELS	CONDITION REFERENCED FROM REQUIRED ACTION D.1
1. RCS Hot Leg Temperature (Wide Range)	2	E
2. RCS Cold Leg Temperature (Wide Range)	2	E
3. RCS Pressure (Wide Range)	2	E
4. Steam Generator (SG) Water Level (Wide or Narrow Range)	2/SG	E
5. Refueling Water Storage Tank Level	2	E
6. Containment Pressure (Narrow Range)	2	E
7. Pressurizer Water Level	2	E
8. Steam Line Pressure	2/SG	E
9. Auxiliary Feedwater Flow Rate	2	E
10. RCS Subcooling Margin Monitor	2	E
11. Containment Water Level (Wide Range)	2	E
12. Core Exit Temperature - Quadrant 1	2[a]	E
13. Core Exit Temperature - Quadrant 2	2[a]	E
14. Core Exit Temperature - Quadrant 3	2[a]	E
15. Core Exit Temperature - Quadrant 4	2[a]	E
16. Reactor Vessel Level Indicating System	2	F
17. Condensate Storage Tank Level	2	E
18. Deleted		
19. Containment Area Radiation (High Range)	2	F

(a) A channel consists of two core exit thermocouples.

DELETED

additional page deleted:
3.6.7-2

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BASES

APPLICABLE SAFETY ANALYSES (continued)

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). The specified Category I, non-Type A, instrumentation must be retained in TS because it is intended to assist operators in minimizing the consequences of accidents. Therefore, these Category I, non-Type A, variables are important for reducing public risk.

LCO

The PAM instrumentation LCO provides OPERABILITY requirements for Regulatory Guide 1.97 Type A monitors, which provide information required by the control room operators to perform certain manual actions specified in the unit Emergency Operating Procedures. These manual actions ensure that a system can accomplish its safety function, and are credited in the safety analyses. Additionally, this LCO addresses certain Regulatory Guide 1.97 instruments that have been designated Category I, non-Type A ~~and one instrument (Hydrogen Monitors) that is neither Category I nor Type A that has been included in this LCO due to its post accident function.~~

The OPERABILITY of the PAM instrumentation ensures there is sufficient information available on selected unit parameters to monitor and assess unit status following an accident. This capability is consistent with the recommendations of Reference 1.

LCO 3.3.3 requires two OPERABLE channels for most Functions. Two OPERABLE channels ensure no single failure prevents operators from getting the information necessary for them to determine the safety status of the unit, and to bring the unit to and maintain it in a safe condition following an accident.

Furthermore, OPERABILITY of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information.

Table 3.3.3-1 lists all Type A and certain Category I variables identified by the unit specific Regulatory Guide 1.97 analyses, as amended by the NRC's SER.

(continued)

BASES

LCO (continued)

17. Condensate Storage Tank (CST) Level

CST Level is provided to ensure water supply for auxiliary feedwater (AFW). The CST provides the ensured safety grade water supply for the AFW System. The CST consists of a tank and outlet header. Inventory is monitored by two .5 – 11 feet of water indications for the tank. CST Level is displayed on control room indicators, and plant computer. In addition, control room annunciators alarm on low and low-low level.

CST Level is considered a Category I, Type A variable because the control room meter and annunciator are considered the primary indication used by the operator.

The DBAs that require AFW are the loss of offsite power, steam line break (SLB), and small break LOCA.

The CST is the initial source of water for the AFW System. However, as the CST is depleted, manual operator action is necessary to replenish the CST or align suction to the AFW pumps from the Service Water System.

DELETED

18. Hydrogen Monitors

Hydrogen Monitors are provided to detect high hydrogen concentration conditions that represent a potential for containment breach from a hydrogen explosion. This variable is also important in verifying the adequacy of mitigating actions. The Hydrogen Monitors are not Type A or Category I instrumentation (Ref. 1). They are included in this LCO due to their post accident function and to maintain consistency with the location of this instrumentation in the Standard Westinghouse Technical Specifications.

19. Containment Area Radiation (High Range)

Containment Area Radiation is a Category I variable provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans. Containment radiation level is used to determine if a high energy line break (HELB) has occurred, and whether the event is inside or outside of containment.

BASES

ACTIONS (continued)

B.1

Condition B applies when the Required Action and associated Completion Time for Condition A are not met. This Required Action specifies initiation of actions in Specification 5.6.8, which requires a written report to be submitted to the NRC. This report discusses the results of the root cause evaluation of the inoperability, if performed, and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability, and given the likelihood of unit conditions that would require information provided by this instrumentation.

C.1

Condition C applies when one or more Functions have two inoperable required channels (i.e., two channels inoperable in the same Function). Required Action C.1 requires restoring one channel in the Function(s) to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

Condition C is modified by a Note that excludes hydrogen monitor channels.

D.1

Condition D applies when two hydrogen monitor channels are inoperable. Required Action D.1 requires restoring one hydrogen monitor channel to OPERABLE status within 72 hours. The 72 hour Completion Time is reasonable based on other core damage assessment capabilities available to provide information for operator decisions. Also, it is unlikely that a LOCA (which would cause core damage) would occur during this time.

(continued)

BASES

ACTIONS (continued)

D

~~E~~.1

Condition ~~E~~ applies when the Required Action and associated Completion Time of Condition C ~~or D~~ are not met. Required Action ~~E~~.1 requires entering the appropriate Condition referenced in Table 3.3.3-1 for the channel immediately. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met any Required Action of Condition C ~~or D~~, and the associated Completion Time has expired, Condition ~~E~~ is entered for that channel and provides for transfer to the appropriate subsequent Condition.

E

D

~~F~~.1 and ~~F~~.2

If the Required Action and associated Completion Time of Conditions C ~~or D~~ are not met and Table 3.3.3-1 directs entry into Condition ~~F~~, the unit must be brought to a MODE where the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and MODE 4 within 12 hours.

E

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

F

~~G~~.1

Alternate means of monitoring Reactor Vessel Water Level and Containment Area Radiation have been developed. These alternate means may be utilized if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. If these alternate means are used, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.6.8, in the Administrative Controls section required to mitigate of the TS. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels. The alternate means of monitoring the affected PAM Channel should be identified or installed, if necessary, prior to submitting the report to the NRC. An acceptable alternate means of monitoring Reactor Vessel Water Level is to monitor pressurizer level and upperhead subcooling.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.2 (continued)

~~The hydrogen monitors are calibrated using sample gases containing:~~

~~a. Ten volume percent hydrogen, balance nitrogen, for zero check.~~

~~b. Ten volume percent hydrogen, balance nitrogen, mixed with compressed air, for span check.~~

The Frequency is based on operating experience and consistency with the typical industry refueling cycle.

REFERENCES

1. A-181866 Unit 1 RG 1.97 Compliance Review
A-204866 Unit 2 RG 1.97 Compliance Review
NRC SER for FNP RG 1.97 Compliance Report, Letter, Reeves to McDonald, 2/12/87.

2. Regulatory Guide 1.97.

3. NUREG-0737, Supplement 1, "TMI Action Items."

Table B 3.3.3-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

{PRIVATE }PAM INSTRUMENTATION	TPNS
RCS Hot Leg Temperature (Wide Range)	TE-413, TE-423, TE-433
RCS Cold Leg Temperature (Wide Range)	TE-410, TE-420, TE-430
RCS Pressure (Wide Range)	PT-402, PT-403
Steam Generator (SG) Water Level	Wide Range – LT-477, LT-487, LT-497
	Narrow Range – LT-474, LT-475, LT-476 LT-484, LT-485, LT-486 LT-494, LT-495, LT-496
Refueling Water Storage Tank Level	LT-501, LT-502
Containment Pressure (Narrow Range)	PT-950, PT-951, PT-952, PT-953
Pressurizer Water Level	LT-459, LT-460, LT-461
Steam Line Pressure	PT-474, PT-475, PT-476 PT-484, PT-485, PT-486 PT-494, PT-495, PT-496
Auxiliary Feewater Flow Rate	FT-3229A, FT-3229B, FT-3229C
RCS Subcooling Margin Monitor	Q1(2) H11NGCCM2523A&B
Containment Water Level (Wide Range)	LT-3594A, LT-3594B
Core Exit Temperature	TE-2301 – TE-2351
Reactor Vessel Level Indicating System	LE-2352, LE-2353
Condensate Storage Tank Level	LT-515, LT-516
~~Hydrogen Monitors~~	~~AIT-2703A, AIT-2703B~~
Containment Area Radiation (High Range)	RE-27A, RE-27B

DELETED

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Hydrogen Recombiners

BASES

BACKGROUND

The function of the hydrogen recombiners is to eliminate the potential breach of containment due to a hydrogen oxygen reaction.

Per 10 CFR 50.44, "Standards for Combustible Gas Control Systems in Light-Water-Cooled Reactors" (Ref. 1), and GDC 41, "Containment Atmosphere Cleanup" (Ref. 2), hydrogen recombiners are required to reduce the hydrogen concentration in the containment following a loss of coolant accident (LOCA) or steam line break (SLB). The recombiners accomplish this by recombining hydrogen and oxygen to form water vapor. The vapor remains in containment, thus eliminating any discharge to the environment. The hydrogen recombiners are manually initiated since flammable limits would not be reached until several days after a Design Basis Accident (DBA).

Two 100% capacity independent hydrogen recombiner systems are provided. Each consists of controls located in the control room, a power supply and a recombiner. Recombination is accomplished by heating a hydrogen air mixture above 1150°F. The resulting water vapor and discharge gases are cooled prior to discharge from the recombiner. A single recombiner is capable of maintaining the hydrogen concentration in containment below the 4.0 volume percent (v/o) flammability limit. Two recombiners are provided to meet the requirement for redundancy and independence. Each recombiner is powered from a separate Engineered Safety Features bus, and is provided with a separate power panel and control panel.

APPLICABLE SAFETY ANALYSES

The hydrogen recombiners provide for the capability of controlling the bulk hydrogen concentration in containment to less than the lower flammable concentration of 4.0 v/o following a DBA. This control would prevent a containment wide hydrogen burn, thus ensuring the pressure and temperature assumed in the analyses are not exceeded. The limiting DBA relative to hydrogen generation is a LOCA. Hydrogen may accumulate in containment following a LOCA as a result of:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant;

b. Radiolytic decomposition of water in the Reactor Coolant System (RCS) and the containment sump;

c. Hydrogen in the RCS at the time of the LOCA (i.e., hydrogen dissolved in the reactor coolant and hydrogen gas in the pressurizer vapor space); or

d. Corrosion of metals exposed to containment spray and Emergency Core Cooling System solutions.

To evaluate the potential for hydrogen accumulation in containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Conservative assumptions recommended by Reference 3 are used to maximize the amount of hydrogen calculated.

Based on the conservative assumptions used to calculate the hydrogen concentration versus time after a LOCA, the hydrogen concentration in the primary containment would reach 3.5 v/o about 13 days after the LOCA and 4.0 v/o about 5 days later if no recombiner was functioning (Ref. 3). Initiating the hydrogen recombiners when the primary containment hydrogen concentration reaches 3.5 v/o will maintain the hydrogen concentration in the primary containment below flammability limits.

The hydrogen recombiners are designed such that, with the conservatively calculated hydrogen generation rates discussed above, a single recombiner is capable of limiting the peak hydrogen concentration in containment to less than 4.0 v/o (Ref. 4). The Post Accident Hydrogen Purge System is designed such that it is an adequate backup to the redundant hydrogen recombiners.

The hydrogen recombiners satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two hydrogen recombiners must be OPERABLE. This ensures operation of at least one hydrogen recombiner in the event of a worst case single active failure.

(continued)

BASES

LCO (continued)

Operation with at least one hydrogen recombiner ensures that the post LOCA hydrogen concentration can be prevented from exceeding the flammability limit.

APPLICABILITY

In MODES 1 and 2, two hydrogen recombiners are required to control the hydrogen concentration within containment below its flammability limit of 4.0 v/o following a LOCA, assuming a worst case single failure.

In MODES 3 and 4, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in these MODES, the probability of an accident requiring the hydrogen recombiners is low. Therefore, the hydrogen recombiners are not required in MODE 3 or 4.

In MODES 5 and 6, the probability and consequences of a LOCA are low, due to the pressure and temperature limitations in these MODES. Therefore, hydrogen recombiners are not required in these MODES.

ACTIONS

A.1

With one containment hydrogen recombiner inoperable, the inoperable recombiner must be restored to OPERABLE status within 30 days. In this condition, the remaining OPERABLE hydrogen recombiner is adequate to perform the hydrogen control function. However, the overall reliability is reduced because a single failure in the OPERABLE recombiner could result in reduced hydrogen control capability. The 30 day Completion Time is based on the availability of the other hydrogen recombiner, the small probability of a LOCA or SLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), and the amount of time available after a LOCA or SLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit.

Required Action A.1 has been modified by a Note that states the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one recombiner is inoperable. This

(continued)

BASES

ACTIONS

A.1 (continued)

allowance is based on the availability of the other hydrogen recombiner, the small probability of a LOCA or SLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), and the amount of time available after a LOCA or SLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit.

B.1 and B.2

With two hydrogen recombiners inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by the containment Post Accident Hydrogen Purge System. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. Both the initial verification and all subsequent verifications may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two hydrogen recombiners inoperable for up to 7 days. Seven days is a reasonable time to allow two hydrogen recombiners to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in the amounts capable of exceeding the flammability limit.

C.1

If the inoperable hydrogen recombiner(s) cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.7.1

Performance of a system functional test for each hydrogen recombiner ensures the recombiners are operational and can attain and sustain the temperature necessary for hydrogen recombination. In particular, this SR verifies that the minimum heater sheath temperature increases to ≥ 700°F in ≤ 90 minutes. After reaching 700°F, the power is increased to maximum power for approximately 2 minutes and power is verified to be ≥ 60 kW.

Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.7.2

This SR ensures there are no physical problems that could affect recombiner operation. Since the recombiners are mechanically passive, they are not subject to mechanical failure. The only credible failure involves loss of power, blockage of the internal flow, missile impact, etc.

A visual inspection is sufficient to determine abnormal conditions that could cause such failures (i.e., loose wiring or structural connections, deposits of foreign materials, etc.). The 18 month Frequency for this SR was developed considering the incidence of hydrogen recombiners failing the SR in the past is low.

SR 3.6.7.3

This SR requires performance of a resistance to ground test for each heater phase to ensure that there are no detectable grounds in any heater phase. This is accomplished by verifying that the resistance to ground for any heater phase is ≥ 10,000 ohms following the performance of the required functional test.

The 18 month Frequency for this Surveillance was developed considering the incidence of hydrogen recombiners failing the SR in the past is low.Comment located at end of above line.

BASES

REFERENCES

1. 10 CFR 50.44.
2. 10 CFR 50, Appendix A, GDC 41.
3. Regulatory Guide 1.7, Revision 1.
4. FSAR Section 6.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.8 Hydrogen Mixing System (HMS)

BASES

The HMS reduces the potential for breach of containment due to a hydrogen oxygen reaction by providing a uniformly mixed post accident containment atmosphere, thereby minimizing the potential for local hydrogen burns due to a pocket of hydrogen above the flammable concentration. Maintaining a uniformly mixed containment atmosphere also ensures that the hydrogen monitors will give an accurate measure of the bulk hydrogen concentration and give the operator the capability of preventing the occurrence of a bulk hydrogen burn inside containment per 10 CFR 50.44, "Standards for Combustible Gas Control Systems in Light-Water-Cooled Reactors" (Ref. 1), and 10 CFR 50, GDC 41, "Containment Atmosphere Cleanup" (Ref. 2).

The post accident HMS is an Engineered Safety Feature (ESF) and is designed to withstand a loss of coolant accident (LOCA) without loss of function. The System has two independent trains, each consisting of two fans with their own motors and controls. Each train is sized for 15,000 cfm. The two trains are initiated automatically on a Safety Injection signal. Each train is powered from a separate emergency power supply. Since a single fan can provide 100% of the mixing requirements, the System will provide its design function with a limiting single active failure.

Air is drawn from the steam generator compartments by the locally mounted mixing fans and is discharged toward the upper regions of the containment. This complements the air patterns established by the containment air coolers, which take suction above the operating floor level and discharge to the lower regions of the containment, and the containment spray, which cools the air and causes it to drop to lower elevations. The systems work together such that potentially stagnant areas where hydrogen pockets could develop are eliminated.

When performing their post accident hydrogen mixing function, the hydrogen mixing fans are designed to prevent motor overload in a post accident high pressure environment. The design flow rate is based on the minimum air distribution requirements to eliminate stagnant hydrogen pockets. Each train is redundant (in excess of full required capacity) and is powered from an independent ESF bus.

BASES

LCO (continued)

by a Safety Injection signal. Only one fan per train is required OPERABLE for the train to be considered OPERABLE.

Operation with at least one HMS fan provides the mixing necessary to ensure uniform hydrogen concentration throughout containment.

APPLICABILITY

In MODES 1 and 2, the two HMS trains ensure the capability to prevent localized hydrogen concentrations above the flammability limit of 4.0 volume percent in containment assuming a worst case single active failure.

In MODE 3 or 4, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in these MODES, the probability of an accident requiring the HMS is low. Therefore, the HMS is not required in MODE 3 or 4.

In MODES 5 and 6, the probability and consequences of a LOCA or steam line break (SLB) are reduced due to the pressure and temperature limitations in these MODES. Therefore, the HMS is not required in these MODES.

ACTIONS

A.1

With one HMS train inoperable, the inoperable train must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE HMS train is adequate to perform the hydrogen mixing function. However, the overall reliability is reduced because a single failure in the OPERABLE train could result in reduced hydrogen mixing capability, although the capacity of a single fan is sufficient to provide adequate mixing. The 30 day Completion Time is based on the availability of the other HMS train, the small probability of a LOCA or SLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), the amount of time available after a LOCA or SLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit, and the availability of the ~~hydrogen recombiners,~~ Containment Spray System, Post Accident Hydrogen Purge System, ~~and hydrogen monitors~~.

and the

(continued)

BASES

ACTIONS

A.1 (continued)

Required Action A.1 has been modified by a Note that states the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one HMS train is inoperable. This allowance is based on the availability of the other HMS train, the small probability of a LOCA or SLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), and the amount of time available after a LOCA or SLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit.

B.1 and B.2

capability is

With two HMS trains inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control ~~capabilities are~~ provided by the containment Post Accident Hydrogen Purge System ~~or a hydrogen recombiner~~. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. Both the initial verification and all subsequent verifications may be performed as an administrative check, by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two HMS trains inoperable for up to 7 days. Seven days is a reasonable time to allow two HMS trains to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in the amounts capable of exceeding the flammability limit.

C.1

If an inoperable HMS train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.8.1

Operating each HMS train for ≥ 15 minutes ensures that each train is OPERABLE and that all associated controls (including starting from the control room) are functioning properly. It also ensures that blockage, fan and/or motor failure, or excessive vibration can be detected for corrective action. While this system is not included in the scope of the Inservice Testing (IST) Program, the 92 day Frequency is consistent with IST Program Surveillance Frequencies, operating experience, the known reliability of the fan motors and controls, and the two train redundancy available.

SR 3.6.8.2

Verifying that each HMS fan speed is ≥ 1320 rpm ensures that each train is capable of maintaining localized hydrogen concentrations below the flammability limit. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.8.3

This SR ensures that each HMS train responds properly to a Safety Injection actuation signal. The Surveillance verifies that each fan starts from the nonoperating condition. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.Comment located at end of above line.

REFERENCES

1. ~~10 CFR 50.44.~~
2. ~~10 CFR 50, Appendix A, GDC 41.~~
3. Regulatory Guide 1.7, Revision 1.
4. WCAP 7901, Revision 1.

DELETED

B 3.6 CONTAINMENT SYSTEMS

B 3.6.9 Reactor Cavity Hydrogen Dilution System (RCHDS)

BASES

BACKGROUND

The RCHDS reduces the potential for breach of containment due to a hydrogen oxygen reaction by providing a uniformly mixed post accident containment atmosphere, thereby minimizing the potential for local hydrogen burns due to a pocket of hydrogen above the flammable concentration. Maintaining a uniformly mixed containment atmosphere also ensures that the hydrogen monitors will give an accurate measure of the bulk hydrogen concentration and give the operator the capability of preventing the occurrence of a bulk hydrogen burn inside containment per 10 CFR 50.44 "Standards for Combustible Gas Control Systems in Light-Water-Cooled Reactors" (Ref. 1), and 10 CFR 50, GDC 41, "Containment Atmosphere Cleanup" (Ref. 2).

The post accident RCHDS is an Engineered Safety Feature (ESF) and is designed to withstand a loss of coolant accident (LOCA) without loss of function. The System has two independent trains, each consisting of one fan with its own motor and controls. Each train is sized for 270 cfm (Unit 1) and 1570 cfm (Unit 2).

The two trains are initiated automatically on a Safety Injection signal. Each train is powered from a separate emergency power supply. Since each train fan can provide 100% of the mixing requirements, the System will provide its design function with a limiting single active failure. The RCHDS ventilates the reactor cavity to ensure that this volume is available for the dilution of containment hydrogen, and to maintain hydrogen concentrations in this volume in equilibrium with that of the remainder of the containment. The RCHDS fans discharge into the reactor cavity through a circular header embedded in the cavity wall at an elevation approximately coincident with that of the lower reactor vessel head. The RCHDS discharge flows from the cavity upward around the reactor vessel and outward through the incore instrument chase. The RCHDS fans take suction from the periphery of the containment just below the operating floor. The design flow rate is based on the minimum air distribution requirements to eliminate stagnant hydrogen pockets. The RCHDS and Hydrogen Mixing System work together such that potentially stagnant areas where hydrogen pockets could develop are eliminated.

BASES

APPLICABILITY (continued)

In MODE 3 or 4, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in these MODES, the probability of an accident requiring the RCHDS is low. Therefore, the RCHDS is not required in MODE 3 or 4.

In MODE 5 or 6, the probability and consequences of a LOCA or steam line break (SLB) are reduced due to the pressure and temperature limitations in these MODES. Therefore, the RCHDS is not required in these MODES.

ACTIONS

A.1

With one RCHDS train inoperable, the inoperabale train must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE RCHDS train is adequate to perform the hydrogen mixing function. However, the overall reliability is reduced because a single failure in the OPERABLE train could result in reduced hydrogen mixing capability. The 30 day Completion Time is based on the availability of the other RCHDS train, the small probability of a LOCA or SLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), the amount of time available after a LOCA or SLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit, and the availability of the ~~hydrogen recombiners,~~ Containment Spray System, Post Accident Venting System ~~, and hydrogen monitors~~ and the .

Required Action A.1 has been modified by a Note that states the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one RCHDS train is inoperable. This allowance is based on the availability of the other RCHDS train, the small probability of a LOCA or SLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), and the amount of time available after a LOCA or SLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit.

B.1

If an inoperable RCHDS train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a

(continued)

BASES

ACTIONS

B.1 (continued)

MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.9.1

Operating each RCHDS train for ≥ 15 minutes ensures that each train is OPERABLE and that all associated controls are functioning properly and that each fan may be started by operator action from the control room. It also ensures that blockage, fan and/or motor failure, or excessive vibration can be detected for corrective action. While this system is not included in the scope of the Inservice Testing (IST) Program, the 92 day Frequency is consistent with IST Program Surveillance Frequencies, operating experience, the known reliability of the fan motors and controls, and the two train redundancy available.

SR 3.6.9.2

This SR ensures that each RCHDS train responds properly to a Safety Injection signal. The Surveillance verifies that each fan starts from the non-operating condition. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. ~~10 CFR 50.44~~
2. ~~10 CFR 50, Appendix A, GDC 41.~~
3. Regulatory Guide 1.7, Revision 0.

DELETED

TABLE OF CONTENTS

BASES

APPLICABLE SAFETY ANALYSES (continued)

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). The specified Category I, non-Type A, instrumentation must be retained in TS because it is intended to assist operators in minimizing the consequences of accidents. Therefore, these Category I, non-Type A, variables are important for reducing public risk.

LCO

The PAM instrumentation LCO provides OPERABILITY requirements for Regulatory Guide 1.97 Type A monitors, which provide information required by the control room operators to perform certain manual actions specified in the unit Emergency Operating Procedures. These manual actions ensure that a system can accomplish its safety function, and are credited in the safety analyses. Additionally, this LCO addresses certain Regulatory Guide 1.97 instruments that have been designated Category I, non-Type A.

The OPERABILITY of the PAM instrumentation ensures there is sufficient information available on selected unit parameters to monitor and assess unit status following an accident. This capability is consistent with the recommendations of Reference 1.

LCO 3.3.3 requires two OPERABLE channels for most Functions. Two OPERABLE channels ensure no single failure prevents operators from getting the information necessary for them to determine the safety status of the unit, and to bring the unit to and maintain it in a safe condition following an accident.

Furthermore, OPERABILITY of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information.

Table 3.3.3-1 lists all Type A and certain Category I variables identified by the unit specific Regulatory Guide 1.97 analyses, as amended by the NRC's SER.

(continued)

BASES

LCO
(continued)

17. Condensate Storage Tank (CST) Level

CST Level is provided to ensure water supply for auxiliary feedwater (AFW). The CST provides the ensured safety grade water supply for the AFW System. The CST consists of a tank and outlet header. Inventory is monitored by two .5 – 11 feet of water indications for the tank. CST Level is displayed on control room indicators, and plant computer. In addition, control room annunciators alarm on low and low-low level.

CST Level is considered a Category I, Type A variable because the control room meter and annunciator are considered the primary indication used by the operator.

The DBAs that require AFW are the loss of offsite power, steam line break (SLB), and small break LOCA.

The CST is the initial source of water for the AFW System. However, as the CST is depleted, manual operator action is necessary to replenish the CST or align suction to the AFW pumps from the Service Water System.

18. Deleted.

19. Containment Area Radiation (High Range)

Containment Area Radiation is a Category I variable provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans. Containment radiation level is used to determine if a high energy line break (HELB) has occurred, and whether the event is inside or outside of containment.

(continued)

BASES

ACTIONS (continued)

B.1

Condition B applies when the Required Action and associated Completion Time for Condition A are not met. This Required Action specifies initiation of actions in Specification 5.6.8, which requires a written report to be submitted to the NRC. This report discusses the results of the root cause evaluation of the inoperability, if performed, and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability, and given the likelihood of unit conditions that would require information provided by this instrumentation.

C.1

Condition C applies when one or more Functions have two inoperable required channels (i.e., two channels inoperable in the same Function). Required Action C.1 requires restoring one channel in the Function(s) to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

(continued)

BASES

ACTIONS (continued)

D.1

Condition D applies when the Required Action and associated Completion Time of Condition C are not met. Required Action D.1 requires entering the appropriate Condition referenced in Table 3.3.3-1 for the channel immediately. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met any Required Action of Condition C and the associated Completion Time has expired, Condition D is entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1 and E.2

If the Required Action and associated Completion Time of Condition C are not met and Table 3.3.3-1 directs entry into Condition E, the unit must be brought to a MODE where the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and MODE 4 within 12 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

F.1

Alternate means of monitoring Reactor Vessel Water Level and Containment Area Radiation have been developed. These alternate means may be utilized if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. If these alternate means are used, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.6.8, in the Administrative Controls section required to mitigate of the TS. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels. The alternate means of monitoring the affected PAM Channel should be identified or installed, if necessary, prior to submitting the report to the NRC. An acceptable alternate means of monitoring Reactor Vessel Water Level is to monitor pressurizer level and upperhead subcooling.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.2 (continued)

The Frequency is based on operating experience and consistency with the typical industry refueling cycle.

REFERENCES

1. A-181866 Unit 1 RG 1.97 Compliance Review
A-204866 Unit 2 RG 1.97 Compliance Review
NRC SER for FNP RG 1.97 Compliance Report, Letter, Reeves to McDonald, 2/12/87.

2. Regulatory Guide 1.97.

3. NUREG-0737, Supplement 1, "TMI Action Items."

Table B 3.3.3-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

PAM INSTRUMENTATION	TPNS
RCS Hot Leg Temperature (Wide Range)	TE-413, TE-423, TE-433
RCS Cold Leg Temperature (Wide Range)	TE-410, TE-420, TE-430
RCS Pressure (Wide Range)	PT-402, PT-403
Steam Generator (SG) Water Level	Wide Range – LT-477, LT-487, LT-497
	Narrow Range – LT-474, LT-475, LT-476 LT-484, LT-485, LT-486 LT-494, LT-495, LT-496
Refueling Water Storage Tank Level	LT-501, LT-502
Containment Pressure (Narrow Range)	PT-950, PT-951, PT-952, PT-953
Pressurizer Water Level	LT-459, LT-460, LT-461
Steam Line Pressure	PT-474, PT-475, PT-476 PT-484, PT-485, PT-486 PT-494, PT-495, PT-496
Auxiliary Feewater Flow Rate	FT-3229A, FT-3229B, FT-3229C
RCS Subcooling Margin Monitor	Q1(2) H11NGCCM2523A&B
Containment Water Level (Wide Range)	LT-3594A, LT-3594B
Core Exit Temperature	TE-2301 – TE-2351
Reactor Vessel Level Indicating System	LE-2352, LE-2353
Condensate Storage Tank Level	LT-515, LT-516
Containment Area Radiation (High Range)	RE-27A, RE-27B

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additional pages deleted:
B 3.6.7-2
B 3.6.7-3
B 3.6.7-4
B 3.6.7-5
B 3.6.7-6

B 3.6 CONTAINMENT SYSTEMS

B 3.6.8 Hydrogen Mixing System (HMS)

BASES

The HMS reduces the potential for breach of containment due to a hydrogen oxygen reaction by providing a uniformly mixed post accident containment atmosphere, thereby minimizing the potential for local hydrogen burns due to a pocket of hydrogen above the flammable concentration.

The post accident HMS is an Engineered Safety Feature (ESF) and is designed to withstand a loss of coolant accident (LOCA) without loss of function. The System has two independent trains, each consisting of two fans with their own motors and controls. Each train is sized for 15,000 cfm. The two trains are initiated automatically on a Safety Injection signal. Each train is powered from a separate emergency power supply. Since a single fan can provide 100% of the mixing requirements, the System will provide its design function with a limiting single active failure.

Air is drawn from the steam generator compartments by the locally mounted mixing fans and is discharged toward the upper regions of the containment. This complements the air patterns established by the containment air coolers, which take suction above the operating floor level and discharge to the lower regions of the containment, and the containment spray, which cools the air and causes it to drop to lower elevations. The systems work together such that potentially stagnant areas where hydrogen pockets could develop are eliminated.

When performing their post accident hydrogen mixing function, the hydrogen mixing fans are designed to prevent motor overload in a post accident high pressure environment. The design flow rate is based on the minimum air distribution requirements to eliminate stagnant hydrogen pockets. Each train is redundant (in excess of full required capacity) and is powered from an independent ESF bus.

BASES

LCO (continued)

by a Safety Injection signal. Only one fan per train is required OPERABLE for the train to be considered OPERABLE.

Operation with at least one HMS fan provides the mixing necessary to ensure uniform hydrogen concentration throughout containment.

APPLICABILITY

In MODES 1 and 2, the two HMS trains ensure the capability to prevent localized hydrogen concentrations above the flammability limit of 4.0 volume percent in containment assuming a worst case single active failure.

In MODE 3 or 4, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in these MODES, the probability of an accident requiring the HMS is low. Therefore, the HMS is not required in MODE 3 or 4.

In MODES 5 and 6, the probability and consequences of a LOCA or steam line break (SLB) are reduced due to the pressure and temperature limitations in these MODES. Therefore, the HMS is not required in these MODES.

ACTIONS

A.1

With one HMS train inoperable, the inoperable train must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE HMS train is adequate to perform the hydrogen mixing function. However, the overall reliability is reduced because a single failure in the OPERABLE train could result in reduced hydrogen mixing capability, although the capacity of a single fan is sufficient to provide adequate mixing. The 30 day Completion Time is based on the availability of the other HMS train, the small probability of a LOCA or SLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), the amount of time available after a LOCA or SLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit, and the availability of the Containment Spray System and the Post Accident Hydrogen Purge System.

(continued)

ACTIONS

A.1 (continued)

Required Action A.1 has been modified by a Note that states the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one HMS train is inoperable. This allowance is based on the availability of the other HMS train, the small probability of a LOCA or SLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), and the amount of time available after a LOCA or SLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit.

B.1 and B.2

With two HMS trains inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capability is provided by the containment Post Accident Hydrogen Purge System. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. Both the initial verification and all subsequent verifications may be performed as an administrative check, by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two HMS trains inoperable for up to 7 days. Seven days is a reasonable time to allow two HMS trains to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in the amounts capable of exceeding the flammability limit.

C.1

If an inoperable HMS train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.8.1

Operating each HMS train for ≥ 15 minutes ensures that each train is OPERABLE and that all associated controls (including starting from the control room) are functioning properly. It also ensures that blockage, fan and/or motor failure, or excessive vibration can be detected for corrective action. While this system is not included in the scope of the Inservice Testing (IST) Program, the 92 day Frequency is consistent with IST Program Surveillance Frequencies, operating experience, the known reliability of the fan motors and controls, and the two train redundancy available.

SR 3.6.8.2

Verifying that each HMS fan speed is ≥ 1320 rpm ensures that each train is capable of maintaining localized hydrogen concentrations below the flammability limit. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.8.3

This SR ensures that each HMS train responds properly to a Safety Injection actuation signal. The Surveillance verifies that each fan starts from the nonoperating condition. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. Deleted
2. Deleted
3. Regulatory Guide 1.7, Revision 1.
4. WCAP 7901, Revision 1.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.9 Reactor Cavity Hydrogen Dilution System (RCHDS)

BASES

BACKGROUND

The RCHDS reduces the potential for breach of containment due to a hydrogen oxygen reaction by providing a uniformly mixed post accident containment atmosphere, thereby minimizing the potential for local hydrogen burns due to a pocket of hydrogen above the flammable concentration.

The post accident RCHDS is an Engineered Safety Feature (ESF) and is designed to withstand a loss of coolant accident (LOCA) without loss of function. The System has two independent trains, each consisting of one fan with its own motor and controls. Each train is sized for 270 cfm (Unit 1) and 1570 cfm (Unit 2).

The two trains are initiated automatically on a Safety Injection signal. Each train is powered from a separate emergency power supply. Since each train fan can provide 100% of the mixing requirements, the System will provide its design function with a limiting single active failure. The RCHDS ventilates the reactor cavity to ensure that this volume is available for the dilution of containment hydrogen, and to maintain hydrogen concentrations in this volume in equilibrium with that of the remainder of the containment. The RCHDS fans discharge into the reactor cavity through a circular header embedded in the cavity wall at an elevation approximately coincident with that of the lower reactor vessel head. The RCHDS discharge flows from the cavity upward around the reactor vessel and outward through the incore instrument chase. The RCHDS fans take suction from the periphery of the containment just below the operating floor. The design flow rate is based on the minimum air distribution requirements to eliminate stagnant hydrogen pockets. The RCHDS and Hydrogen Mixing System work together such that potentially stagnant areas where hydrogen pockets could develop are eliminated.

(continued)

BASES

APPLICABILITY (continued)

In MODE 3 or 4, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in these MODES, the probability of an accident requiring the RCHDS is low. Therefore, the RCHDS is not required in MODE 3 or 4.

In MODE 5 or 6, the probability and consequences of a LOCA or steam line break (SLB) are reduced due to the pressure and temperature limitations in these MODES. Therefore, the RCHDS is not required in these MODES.

ACTIONS

A.1

With one RCHDS train inoperable, the inoperabale train must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE RCHDS train is adequate to perform the hydrogen mixing function. However, the overall reliability is reduced because a single failure in the OPERABLE train could result in reduced hydrogen mixing capability. The 30 day Completion Time is based on the availability of the other RCHDS train, the small probability of a LOCA or SLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), the amount of time available after a LOCA or SLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit, and the availability of the Containment Spray System and the Post Accident Venting System.

Required Action A.1 has been modified by a Note that states the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one RCHDS train is inoperable. This allowance is based on the availability of the other RCHDS train, the small probability of a LOCA or SLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), and the amount of time available after a LOCA or SLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit.

B.1

If an inoperable RCHDS train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a

(continued)

BASES

ACTIONS

B.1 (continued)

MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.9.1

Operating each RCHDS train for ≥ 15 minutes ensures that each train is OPERABLE and that all associated controls are functioning properly and that each fan may be started by operator action from the control room. It also ensures that blockage, fan and/or motor failure, or excessive vibration can be detected for corrective action. While this system is not included in the scope of the Inservice Testing (IST) Program, the 92 day Frequency is consistent with IST Program Surveillance Frequencies, operating experience, the known reliability of the fan motors and controls, and the two train redundancy available.

SR 3.6.9.2

This SR ensures that each RCHDS train responds properly to a Safety Injection signal. The Surveillance verifies that each fan starts from the non-operating condition. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. Deleted
2. Deleted
3. Regulatory Guide 1.7, Revision 0.

Enclosure 4

Edwin I. Hatch Nuclear Plant
Joseph M. Farley Nuclear Plant
Vogtle Electric Generating Plant
Application for Technical Specification Amendment to
Eliminate Requirements for Hydrogen Recombiners and Hydrogen and Oxygen Monitors
Using the Consolidated Line Item Improvement Process

VEGP Marked-up and Clean Typed TS and Bases Pages

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. (continued) ----------NOTE---------- Applicable to those functions with only one required channel per loop, SG, or steam line. ---------- One channel inoperable and no diverse channel OPERABLE.		
~~I. Two Hydrogen Monitors inoperable.~~	~~I.1 Restore one Monitor to OPERABLE status.~~	~~72 hours~~
J. ----------NOTE---------- Not applicable to Containment Radiation and RVLIS functions. ---------- Required Action and associated Completion Time of Condition H ~~or I~~ not met.	J.1 Be in MODE 4.	12 hours
K. ----------NOTE---------- Applicable to Containment Radiation and RVLIS functions only. ---------- Required Action and asociated Completion Time of Condition H not met.	K.1 Initiate action in accordance with Specification 5.6.8.	Immediately

Table 3.3.3-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

FUNCTION	REQUIRED CHANNELS	CONDITIONS
1. Reactor Coolant System (RCS) Pressure (wide range)	2	B,G,H,[illegible] ← I
2. RCS T_{hot} (wide range)	1/loop	C,G,H,[illegible] ← I
3. RCS T_{cold} (wide range)	1/loop	D,G,H,[illegible] ← I
4. Steam Generator (SG) Water Level (wide range)	1/SG	E,G,H,[illegible] ← I
5. SG Water Level (narrow range)	2/SG	B,G,H,[illegible] ← I
6. Pressurizer Level	2	B,G,H,[illegible] ← I
7. Containment Pressure	2	B,G,H,[illegible] ← I
8. Steam line Pressure	2/steam line	B,G,H,[illegible] ← I
9. Refueling Water Storage Tank (RWST) Level	2	B,G,H,[illegible] ← I
10. Containment Normal Sumps Level (narrow range)	2	B,G,H,[illegible] ← I
11. Containment Water Level (wide range)	2	B,G,H,[illegible] ← I
12. Condensate Storage Tank Level	2/tank[a]	B,G,H,[illegible] ← I
13. Auxiliary Feedwater Flow	2/SG	B,G,H,[illegible] ← I
14. Containment Radiation Level (high range)	2	B,G,H,[illegible] ← J
15. Steam line Radiation Monitor	1/steam line	F,G,H,[illegible] ← I
16. RCS Subcooling	2	B,G,H,[illegible] ← I
17. Neutron Flux (extended range)	2	B,G,H,[illegible] ← I
Deleted 18. Reactor Vessel Water Level (RVLIS)	2	B,G,H,[illegible] ← J
19. ~~Hydrogen Monitors~~	~~[illegible]~~	~~B,G,I,J~~
20. Containment Pressure (extended range)	2	B,G,H,[illegible] ← I
21. Containment Isolation Valve Position	2/penetration flow path[b] [c]	B,G,H,[illegible] ← I
22. Core Exit Temperature - Quadrant 1	2[d]	B,G,H,[illegible] ← I
23. Core Exit Temperature - Quadrant 2	2[d]	B,G,H,[illegible] ← I
24. Core Exit Temperature - Quadrant 3	2[d]	B,G,H,[illegible] ← I
25. Core Exit Temperature - Quadrant 4	2[d]	B,G,H,[illegible] ← I

(a) Only required for the OPERABLE tank.

(b) Not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

Applicable for containment isolation valve position indication designated as post-accident monitoring instrumentation (containment isolation valves which receive containment isolation phase A or containment ventilation isolation signals).

(c) Only one position indication channel is required for penetration flow paths with only one installed control room indication channel.

(d) A channel consists of two core exit thermocouples (CETs).

DELETED

3.6 CONTAINMENT SYSTEMS

3.6.7 Hydrogen Recombiners

LCO 3.6.7 Two hydrogen recombiners shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One hydrogen recombiner inoperable.	A.1	----------NOTE---------- LCO 3.0.4 is not applicable. ---------- Restore hydrogen recombiner to OPERABLE status.	30 days
B. Two hydrogen recombiners inoperable.	B.1	Verify by administrative means that the hydrogen control function is maintained.	1 hour AND Once per 12 hours thereafter
	AND		
	B.2	Restore one hydrogen recombiner to OPERABLE status.	7 days
C. Required Action and associated Completion Time not met.	C.1	Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.7.1	Perform a system functional test for each hydrogen recombiner.	18 months
SR 3.6.7.2	Visually examine each hydrogen recombiner enclosure and verify there is no evidence of abnormal conditions.	18 months
SR 3.6.7.3	Perform a resistance to ground test for each heater phase.	18 months

5.6 Reporting Requirements

5.6.6 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR) (continued)

3. Letter from C. I. Grimes, NRC, to R. A. Newton, Westinghouse Electric Corporation, "Acceptance for Referencing of Topical Report WCAP-14040, Revision 1, 'Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves,'" October 16, 1995.

4. Letter from C. K. McCoy, Georgia Power Company, to U.S. Nuclear Regulatory Commission, Attention: Document Control Desk, "Vogtle Electric Generating Plant, Pressure and Temperature Limits Report," Enclosures 1 and 2, January 26, 1996.

d. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement thereto.

5.6.7 EDG Failure Report

If an individual emergency diesel generator (EDG) experiences four or more valid failures in the last 25 demands, these failures and any nonvalid failures experienced by that EDG in that time period shall be reported within 30 days. Reports on EDG failures shall include the information recommended in Regulatory Guide 1.9, Revision 3, Regulatory Position C.4, or existing Regulatory Guide 1.108 reporting requirement.

5.6.8 PAM Report J

When a Report is required by Condition G or K of LCO 3.3.3, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

(continued)

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. (continued) ----------NOTE---------- Applicable to those functions with only one required channel per loop, SG, or steam line. ---------- One channel inoperable and no diverse channel OPERABLE.		
I. ----------NOTE---------- Not applicable to Containment Radiation and RVLIS functions. ---------- Required Action and associated Completion Time of Condition H not met.	I.1 Be in MODE 4.	12 hours
J. ----------NOTE---------- Applicable to Containment Radiation and RVLIS functions only. ---------- Required Action and asociated Completion Time of Condition H not met.	J.1 Initiate action in accordance with Specification 5.6.8.	Immediately

Table 3.3.3-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

FUNCTION	REQUIRED CHANNELS	CONDITIONS
1. Reactor Coolant System (RCS) Pressure (wide range)	2	B,G,H,I
2. RCS T_{hot} (wide range)	1/loop	C,G,H,I
3. RCS T_{cold} (wide range)	1/loop	D,G,H,I
4. Steam Generator (SG) Water Level (wide range)	1/SG	E,G,H,I
5. SG Water Level (narrow range)	2/SG	B,G,H,I
6. Pressurizer Level	2	B,G,H,I
7. Containment Pressure	2	B,G,H,I
8. Steam line Pressure	2/steam line	B,G,H,I
9. Refueling Water Storage Tank (RWST) Level	2	B,G,H,I
10. Containment Normal Sumps Level (narrow range)	2	B,G,H,I
11. Containment Water Level (wide range)	2	B,G,H,I
12. Condensate Storage Tank Level	2/tank[a]	B,G,H,I
13. Auxiliary Feedwater Flow	2/SG	B,G,H,I
14. Containment Radiation Level (high range)	2	B,G,H,J
15. Steam line Radiation Monitor	1/steam line	F,G,H,I
16. RCS Subcooling	2	B,G,H,I
17. Neutron Flux (extended range)	2	B,G,H,I
18. Reactor Vessel Water Level (RVLIS)	2	B,G,H,J
19. Deleted		
20. Containment Pressure (extended range)	2	B,G,H,I
21. Containment Isolation Valve Position	2/penetration flow path[b] [c]	B,G,H,I
22. Core Exit Temperature - Quadrant 1	2[d]	B,G,H,I
23. Core Exit Temperature - Quadrant 2	2[d]	B,G,H,I
24. Core Exit Temperature - Quadrant 3	2[d]	B,G,H,I
25. Core Exit Temperature - Quadrant 4	2[d]	B,G,H,I

(a) Only required for the OPERABLE tank.

(b) Not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

Applicable for containment isolation valve position indication designated as post-accident monitoring instrumentation (containment isolation valves which receive containment isolation phase A or containment ventilation isolation signals).

(c) Only one position indication channel is required for penetration flow paths with only one installed control room indication channel.

(d) A channel consists of two core exit thermocouples (CETs).

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5.6 Reporting Requirements

5.6.6 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR) (continued)

3. Letter from C. I. Grimes, NRC, to R. A. Newton, Westinghouse Electric Corporation, "Acceptance for Referencing of Topical Report WCAP-14040, Revision 1, 'Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves,'" October 16, 1995.

4. Letter from C. K. McCoy, Georgia Power Company, to U.S. Nuclear Regulatory Commission, Attention: Document Control Desk, "Vogtle Electric Generating Plant, Pressure and Temperature Limits Report," Enclosures 1 and 2, January 26, 1996.

d. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement thereto.

5.6.7 EDG Failure Report

If an individual emergency diesel generator (EDG) experiences four or more valid failures in the last 25 demands, these failures and any nonvalid failures experienced by that EDG in that time period shall be reported within 30 days. Reports on EDG failures shall include the information recommended in Regulatory Guide 1.9, Revision 3, Regulatory Position C.4, or existing Regulatory Guide 1.108 reporting requirement.

5.6.8 PAM Report

When a Report is required by Condition G or J of LCO 3.3.3, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

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(continued)

BASES

LCO (continued)

18. Reactor Vessel Water Level

Reactor Vessel Water Level (LT1310, LT1311, LT1312, LT1320, LT1321, & LT1322) is provided for verification and long term surveillance of core cooling. It is also used for accident diagnosis and to determine reactor coolant inventory adequacy. A RVLIS channel consists of Full Range, Upper Range, and Dynamic Range transmitters. LT1310 and LT1320 are Upper Range, LT1311 and LT1321 are Full Range, and LT1312 and LT1322 are Dynamic Range.

The Reactor Vessel Water Level Monitoring System provides a direct measurement of the collapsed liquid level above the uppercore plate. The collapsed level represents the amount of liquid mass that is in the reactor vessel above the core. Measurement of the collapsed water level is selected because it is a direct indication of the water inventory.

~~19. Hydrogen Monitors~~

~~Hydrogen Monitors (Loops 12979 & 12980) are provided to detect high hydrogen concentration conditions that represent a potential for containment breach from a hydrogen explosion. This variable is also important in verifying the adequacy of mitigating actions.~~

21. Containment Isolation Valve Position

CIV Position is provided for verification of Containment OPERABILITY, and Phase A isolation.

When used to verify Phase A isolation, the important information is the isolation status of the containment penetrations. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each active containment isolation valve in a containment penetration flow path, i.e., two total channels of containment isolation valve position indication for a penetration flow path with two active valves. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve, as applicable, and prior knowledge of a passive valve, or via system boundary status. If a normally active CIV is known to be closed and deactivated, position

(continued)

BASES

ACTIONS
(continued)

~~I.1~~

~~Condition I applies when two hydrogen monitor channels are inoperable. Required Action I.1 requires restoring one hydrogen monitor channel to OPERABLE status within 72 hours. The 72 hour Completion Time is reasonable because it is unlikely that a LOCA (which would cause core damage) would occur during this time.~~

J.1

If the Required Action and associated Completion Time of Conditions H ~~or I~~ are not met and Table 3.3.3-1 directs entry into Condition J, the unit must be brought to a MODE where the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least MODE 4 within 12 hours.

The allowed Completion Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Condition J is modified by a Note that excludes the Containment Radiation and RVLIS Functions. These Functions are addressed by another Condition.

K.1

Alternate means of monitoring Reactor Vessel Water Level (RVLIS) and Containment Area Radiation are available. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. If these alternate means are used, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.6.8, in the Administrative Controls section of the TS. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas

(continued)

BASES

ACTIONS

J

K.1 (continued)

in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1.

SR 3.3.3.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross instrumentation failure has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The high radiation instrumentation should be compared to similar unit instruments located throughout the unit.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE.

The Frequency of 31 days is based on operating experience that demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Hydrogen Recombiners

BASES

BACKGROUND

The function of the hydrogen recombiners is to eliminate the potential breach of containment due to a hydrogen/oxygen reaction.

Per 10 CFR 50.44, "Standards for Combustible Gas Control Systems in Light-Water-Cooled Reactors" (Ref. 1), and GDC 41, "Containment Atmosphere Cleanup" (Ref. 2), hydrogen recombiners are required to reduce the hydrogen concentration in the containment following a loss of coolant accident (LOCA) or steam line break (SLB). The recombiners accomplish this by recombining hydrogen and oxygen to form water vapor. The vapor remains in containment, thus eliminating any discharge to the environment. The hydrogen recombiners are manually initiated since flammable limits would not be reached until several days after a Design Basis Accident (DBA).

Two 100% capacity independent hydrogen recombiner systems are provided. Each consists of controls located in the control building, a power supply, and a recombiner. Recombination is accomplished by heating a hydrogen air mixture above 1150°F. The resulting water vapor and discharge gases are cooled prior to discharge from the recombiner. A single recombiner is capable of maintaining the hydrogen concentration in containment below the 4.1 volume percent (v/o) flammability limit. Two recombiners are provided to meet the requirement for redundancy and independence. Each recombiner is powered from a separate Engineered Safety Features bus and is provided with a separate power panel and control panel.

APPLICABLE SAFETY ANALYSES

The hydrogen recombiners provide for the capability of controlling the bulk hydrogen concentration in containment to less than the lower flammable concentration of 4.1 v/o following a DBA. This control would prevent a containment- wide hydrogen burn, thus ensuring the pressure and temperature assumed in the analyses are not exceeded. The limiting DBA relative to hydrogen generation is a LOCA.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Hydrogen may accumulate in containment following a LOCA as a result of:

a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant;

b. Radiolytic decomposition of water in the Reactor Coolant System (RCS) and the containment sump;

c. Hydrogen in the RCS at the time of the LOCA (i.e., hydrogen dissolved in the reactor coolant and hydrogen gas in the pressurizer vapor space); or

d. Corrosion of metals exposed to containment spray and Emergency Core Cooling System solutions.

To evaluate the potential for hydrogen accumulation in containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Conservative assumptions recommended by Reference 3 are used to maximize the amount of hydrogen calculated.

Based on the conservative assumptions used to calculate the hydrogen concentration versus time after a LOCA, the hydrogen concentration in the primary containment would reach 3.5 v/o about 6 days after the LOCA and 4.0 v/o about 2 days later if no recombiner was functioning (Ref. 3). Initiating the hydrogen recombiners when the primary containment hydrogen concentration reaches 3.5 v/o will maintain the hydrogen concentration in the primary containment below flammability limits.

The hydrogen recombiners are designed such that, with the conservatively calculated hydrogen generation rates discussed above, a single recombiner is capable of limiting the peak hydrogen concentration in containment to less than 4.0 v/o (Ref. 3). The Hydrogen Purge System is similarly designed such that one of two redundant trains is an adequate backup to the redundant hydrogen recombiners.

The hydrogen recombiners satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

(continued)

BASES (continued)

LCO

Two hydrogen recombiners must be OPERABLE. This ensures operation of at least one hydrogen recombiner in the event of a worst case single active failure.

Operation with at least one hydrogen recombiner ensures that the post LOCA hydrogen concentration can be prevented from exceeding the flammability limit.

APPLICABILITY

In MODES 1 and 2, two hydrogen recombiners are required to control the hydrogen concentration within containment below its flammability limit of 4.1 v/o following a LOCA, assuming a worst case single failure.

In MODES 3 and 4, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in these MODES, the probability of an accident requiring the hydrogen recombiners is low. Therefore, the hydrogen recombiners are not required in MODE 3 or 4.

In MODES 5 and 6, the probability and consequences of a LOCA are low, due to the pressure and temperature limitations in these MODES. Therefore, hydrogen recombiners are not required in these MODES.

ACTIONS

A.1

With one containment hydrogen recombiner inoperable, the inoperable recombiner must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE hydrogen recombiner is adequate to perform the hydrogen control function. However, the overall reliability is reduced because a single failure in the OPERABLE recombiner could result in reduced hydrogen control capability. The 30 day Completion Time is based on the availability of the other hydrogen recombiner, the small probability of a LOCA or SLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), and the amount of time available after a LOCA or SLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit.

(continued)

BASES

ACTIONS

A.1 (continued)

Required Action A.1 has been modified by a Note that states the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one recombiner is inoperable. This allowance is based on the availability of the other hydrogen recombiner, the small probability of a LOCA or SLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), and the amount of time available after a LOCA or SLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit.

B.1 and B.2

With two hydrogen recombiners inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by the containment Hydrogen Purge System/Containment Air Dilution System. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. In addition, the alternate hydrogen control system capability must be verified every 12 hours thereafter to ensure its continued availability. Both the initial verification and all subsequent verifications may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the Surveillances or other testing needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two hydrogen recombiners inoperable for up to 7 days. Seven days is a reasonable time to allow two hydrogen recombiners to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in the amounts capable of exceeding the flammability limit.

(continued)

BASES

ACTIONS (continued)

C.1

If the inoperable hydrogen recombiner(s) cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.7.1

Performance of a system functional test for each hydrogen recombiner ensures the recombiners are operational and can attain and sustain the temperature necessary for hydrogen recombination. In particular, this SR verifies that the minimum heater sheath temperature increases to ≥ 700°F in ≤ 90 minutes. After reaching 700°F, the power is increased to maximum power for approximately 2 minutes and power is verified to be ≥ 60 kW.

Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.7.2

This SR ensures there are no physical problems that could affect recombiner operation. Since the recombiners are mechanically passive, they are not subject to mechanical failure. The only credible failure involves loss of power, blockage of the internal flow, missile impact, etc.

A visual inspection is sufficient to determine abnormal conditions that could cause such failures. The 18 month Frequency for this SR was developed considering the incidence of hydrogen recombiners failing the SR in the past is low.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.7.3

This SR requires performance of a resistance to ground test for each heater phase to ensure that there are no detectable grounds in any heater phase. This is accomplished by verifying that the resistance to ground for any heater phase is ≥ 10,000 ohms.

The 18 month Frequency for this Surveillance was developed considering the incidence of hydrogen recombiners failing the SR in the past is low.

REFERENCES

1. 10 CFR 50.44.

2. 10 CFR 50, Appendix A, GDC 41.

3. Regulatory Guide 1.7, Revision 2.

(continued)

BASES

LCO (continued)

18. Reactor Vessel Water Level

Reactor Vessel Water Level (LT1310, LT1311, LT1312, LT1320, LT1321, & LT1322) is provided for verification and long term surveillance of core cooling. It is also used for accident diagnosis and to determine reactor coolant inventory adequacy. A RVLIS channel consists of Full Range, Upper Range, and Dynamic Range transmitters. LT1310 and LT1320 are Upper Range, LT1311 and LT1321 are Full Range, and LT1312 and LT1322 are Dynamic Range.

The Reactor Vessel Water Level Monitoring System provides a direct measurement of the collapsed liquid level above the uppercore plate. The collapsed level represents the amount of liquid mass that is in the reactor vessel above the core. Measurement of the collapsed water level is selected because it is a direct indication of the water inventory.

21. Containment Isolation Valve Position

CIV Position is provided for verification of Containment OPERABILITY, and Phase A isolation.

When used to verify Phase A isolation, the important information is the isolation status of the containment penetrations. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each active containment isolation valve in a containment penetration flow path, i.e., two total channels of containment isolation valve position indication for a penetration flow path with two active valves. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve, as applicable, and prior knowledge of a passive valve, or via system boundary status. If a normally active CIV is known to be closed and deactivated, position

(continued)

BASES

ACTIONS (continued)

I.1

If the Required Action and associated Completion Time of Conditions H are not met and Table 3.3.3-1 directs entry into Condition I, the unit must be brought to a MODE where the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least MODE 4 within 12 hours.

The allowed Completion Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Condition I is modified by a Note that excludes the Containment Radiation and RVLIS Functions. These Functions are addressed by another Condition.

J.1

Alternate means of monitoring Reactor Vessel Water Level (RVLIS) and Containment Area Radiation are available. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. If these alternate means are used, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.6.8, in the Administrative Controls section of the TS. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas

(continued)

BASES

ACTIONS

J.1 (continued)

in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1.

SR 3.3.3.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross instrumentation failure has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The high radiation instrumentation should be compared to similar unit instruments located throughout the unit.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE.

The Frequency of 31 days is based on operating experience that demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

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